Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

Dean K. Matsuura
Manager
Regulatory Affairs

August 17, 2009

FILED

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PUBLIC UTILITIES
COMMISSION

The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
Kekuanaoa Building, First Floor
465 South King Street
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 2008-0083 – Hawaiian Electric 2009 Test Year Rate Case
<u>Hawaiian Electric's Responses to Commission Information Requests</u>

Enclosed for filing are Hawaiian Electric Company, Inc.'s ("Hawaiian Electric" or "Company") responses to information requests ("IRs") issued by the Commission to Hawaiian Electric on August 3, 2009, including PUC IRs 108, 112, 114, and 115.

The response to PUC-IR-115 contains confidential information and is provided subject to the Protective Order filed on November 21, 2008 in this proceeding.

Under separate cover, the Company is requesting the Commission's approval for an extension of time, until August 20, 2009, to file responses to PUC IRs 106, 107, and 109.

Very truly yours,

for
Dean K. Matsuura
Manager, Regulatory Affairs

Enclosures

cc: Division of Consumer Advocacy
Michael L. Brosch, Utilitech, Inc.
Joseph A. Herz, Sawvel & Associates, Inc.
Dr. Kay Davoodi, Department of Defense
James N. McCormick, Department of Defense
Theodore E. Vestal, Department of Defense
Ralph Smith, Larkin & Associates

PUC-IR-108

Reference: Act 162 (2006)
HECO ST-10B at 17

HECO filed Supplemental Testimony of Dr. Jeff D. Makholm, on Behalf of Hawaiian Electric Company, Inc. on July 20,2009. Dr. Makholm stated the following:

> ...Most states currently have a form of budget billing program available to residential customers.

Please provide:

a) the estimated costs of budget billing programs for at least three utilities that have a similar number of residential customers as HECO;
b) advantages and disadvantages to HECO and its customers of providing a budget billing program, including but not limited to, rate smoothing; and
c) reasons why HECO considers a budget billing program to be not reasonable or cost-effective for HECO.

HECO Response:

a. The requested information is not readily available. The publicly available data for other similar-sized electric utilities does not allow for separating the costs specific to budget billing from the general operating expenses.

To provide additional information to the Commission, it may be useful to point out that it is difficult to assess costs that pertain specifically to budget billing, as it is part of a suite of billing options, which also includes traditional usage-based billing and various types of special rate plans (e.g., time-of-use, standby service, off-peak and curtailable service, etc.). Moreover, many electric utilities have had budget billing programs in place for many years, so only the variable "running" cost of the program would be relevant for those companies.

In general, the costs of a budget billing program can be categorized into the upfront non-recurring costs of establishing the program, and the recurring costs of running it. The upfront non-recurring costs would include the costs of regulatory process and approval, as well as development and implementation of the necessary usage forecast models, modifications to the billing systems, initial customer service staff training, program launch marketing and promotion costs, and initial customer education and outreach (brochures, etc.). The recurrent costs would include maintenance and operation of these systems, processes, marketing and customer education collateral materials, and the annual reconciliation for each participating customer of billed amounts under budget billing versus what the actual billed amounts would have been under a non-budget billing plan and determining the additional amount or credit to be added to the customer bill following the reconciliation.

b. The benefit to HECO utility customers from budget billing is that some customers (e.g., those on fixed incomes) would benefit from predictability of the monthly energy bill, which would help those particular customers to mitigate the effects of volatile changes in monthly energy costs. The voluntary nature of these programs limits negative consumer feedback and targets the program to the consumers that want them. With the effective extension of the payment horizon for the full cost of consumed energy over the course of a year, consumers could be better able to plan their finances.

Budget billing would be developed and implemented as part of HECO's traditional provision of utility service and there would be non-recurring upfront and recurring running costs associated with the budget billing program, which would require the Company to incur costs that it otherwise would not. Moreover, it is possible that a budget billing program could benefit the utility's ratepayers by leading to a decline in bad debt expense if those customers that participate in a budget billing program are better able to pay their utility bills in a timely manner.

The disadvantage of budget billing is that "At the end of the year, there is a true-up between the amount paid by the ratepayer and the amount the ratepayer would have paid, given his actual usage, under a non-budget billing rate plan." (HECO ST-10B, page 17, lines 1-3.) The amount of true-up would not be known to the customer until it is billed at the end of the year. The size of the true-up depends on the usage and electricity price used to estimate the fixed bill that the customer would pay for that year. Depending on how the estimated usage and electricity price compared to the actual usage and electricity price during the year, the true-up could be either an additional payment or a credit on the customer's next bill after the end of the year. For example, if the customer's actual annual usage was greater than the estimate and/or if the actual electricity prices were higher than the estimate due to an increase in fuel prices, the true-up could be positive and the customer would have to pay his normal electricity bill, plus pay the true-up. A different relationship between the estimates and actuals could result in the true-up being a credit to the bill and reduce it below the normal electricity bill amount.

As can be seen, if the customer does not know what the true-up amount is, it will be difficult for the customer to anticipate the amount he/she will need to pay for the bill that follows the end of the year. If the true-up amount is a large payment due, say to increasing fuel prices, the customer may find himself/herself in a difficult financial position. This could have an adverse effect on bad debts to HECO.

c. HECO does not consider a budget billing program to be not reasonable or cost effective. In fact, in HELCO's test year 2006 rate case (Docket No. 05-0135), HELCO proposed that it would explore an optional revenue neutral budget billing rate schedule for residential and Schedule G customers and submit to the Commission, within 12 months from the date of the Commission's final decision and order in that docket, a pilot budget billing program for its review. It further indicated that "HELCO cannot currently implement budget billing using its existing customer information system ("CIS"). The new CIS, however, can handle budget billing, but is not expected to be in-service until the first half of 2008. Therefore, while HELCO may submit its pilot budget billing program and tariff for Commission review within 12 months of the Commission's final D&O in this docket, the schedule for actual implementation of the pilot depends on the in-service date for the new CIS." (HELCO RT-22, page 7, lines 1 – 12.)

The new CIS is currently not in-service, but HECO also proposes to submit for Commission review within 12 months from the date of the Commission's final decision and order in the instant docket, a pilot budget billing program for its review. As is the case for HELCO, the schedule for actual implementation of the HECO pilot depends on the in-service date for the new CIS.

PUC-IR-112

Reference: 3rd Party Parallel Planning Costs

a) Has HECO included 3rd party parallel planning costs in the 2009 test year?
b) If yes, what competitively bid project does the 2009 test year parallel planning cost apply to?
c) How does HECO differentiate between 3rd party parallel planning costs attributed to the competitive bidding process and normalized planning costs that are expected of a utility's operation?
d) Should 3rd party parallel planning occur for projects that were waived from the competitive bidding process? Please explain.

<u>HECO Response:</u>

a. Hawaiian Electric assumes that the term "3rd party parallel planning" used in this Information Request has the same meaning as "Parallel Plan" as defined in the Framework for Competitive Bidding issued by the Commission on December 8, 2006, as Exhibit A to Decision and Order No. 23121 in Docket No. 03-0372 (the "Competitive Bidding Framework"):

> "Parallel Plan" means the generating unit plan (comprised of one or multiple generation resources) that is pursued by the electric utility in parallel with a third-party project selected in an RFP until there is reasonable assurance that the third-party project will reach commercial operation, or until such action can no longer be justified to be reasonable. The utility's Parallel Plan unit(s) may be different from that proposed in the utility's bid. The term "utility's bid," as used herein, refers to a utility's proposal advanced in response to a need that is addressed by its RFP.

With that understanding, the answer to part a) of this information request is no.

b. Not applicable.

c. Hawaiian Electric assumes that the term "normalized planning process" used in this Information Request refers to the Company's routine, on-going planning activities carried out by areas within the Company such as the Generation Planning Division.

To date, Hawaiian Electric has not engaged in Parallel Planning as defined in the response to part a. of this Information Request because the competitive bidding process under the Competitive Bidding Framework has not been used to acquire firm capacity resources. In the event Parallel Planning becomes appropriate in a future procurement process, the costs of Parallel Planning will be handled in accordance with Parts VII.B and VII.C of the Competitive Bidding Framework:

> B. The costs that an electric utility incurs in taking reasonable and prudent steps to implement Parallel Plans and Contingency Plans are recoverable through the utility's rates, to the extent reasonable and prudent, as part of the cost of providing reliable service to customers"
>
> C. The reasonable and prudent capital costs that are part of an electric utility's Parallel Plans and Contingency Plans shall be accounted for similar to costs for planning other capital projects (provided that such accounting treatment shall not be determinative of ratemaking treatment):
>
> 1. Such costs would be accumulated as construction work in progress, and carrying costs would accrue on such costs. If the Parallel Plans or Contingency Plans, as implement, result in the addition of planned resources to the utility system, then the costs incurred and accrued carrying charges would be capitalized as part of the installed resources (i.e., recorded to plant-in-service) and added to rate base. The costs would be depreciated over the life of the resource additions.
>
> 2. If implementation of the Parallel Plans or Contingency Plans is terminated before the resources identified in such plans are placed into service, the costs incurred and accrued carrying charges included in construction work in progress would be transferred to a miscellaneous deferred debit account and the balance would be amortized to expense over five years (or a reasonable period determined by the Commission), beginning when the base plan resource is placed into service. The amortization expense would be included in the utility's revenue requirement when there is a general rate case. Under appropriate circumstances, the Commission may allow additional carrying costs to accrue on the unamortized miscellaneous deferred balance.

Typically, routine, on-going planning activities are O&M expenses.

d. Yes, it may be prudent to use parallel planning in projects for which the Commission has granted a waiver from competitive bidding.

The Competitive Bidding Framework, in Part II.A.3, sets forth circumstances in which competitive bidding may not be appropriate, for example, when competitive bidding would unduly hinder the ability to add needed generation in a timely fashion. In such circumstances, the Commission may grant a waiver from the competitive bidding process for acquiring new generation resources from third parties. Competitive Bidding Framework, Part II.A.3.b.i.

The Competitive Bidding Framework recognizes the role of Parallel Planning in mitigating the risks associated with competitive bidding, "In consideration of the isolated nature of the island utility systems, the utility may use a Parallel Plan option to mitigate the risk that an IPP's option may fail...." Competitive Bidding Framework, Section II.D.2, page 9. The Competitive Bidding Framework acknowledges that Parallel Planning is appropriate where Hawaiian Electric is addressing a need for firm capacity in order to deal with system reliability issues or concerns. See, Competitive Bidding Framework, Part VI. A.2.c , page 29.

Whether a third party generation resource is selected through the competitive bidding process or is selected through another means of procurement, the potential risk is the same where Hawaiian Electric is acquiring additional generation resource in order to deal with system reliability issues or concerns. In either circumstance, Parallel Planning plays an important role in mitigating the risk that a project may be delayed or not completed.

PUC-IR-114

Reference: Purchased Power Adjustment Clause

a) Are there other jurisdictions that have implemented a PPAC, or similar mechanism, for the purposes of mitigating imputed debt?
b) Please provide reference and evidence to show that the risk factors for these utilities in other jurisdictions were reduced.

HECO Response:

a. One example in which a mechanism was implemented that resulted in mitigating imputed debt is in the State of Vermont. In October 2008, the Vermont Public Service Board approved a Central Vermont Public Service ("CVPS") alternative regulation plan to better link customer and investor interests, improve efficiency and help control costs. The plan provides for, among other things, automatically adjusting rates on a quarterly basis to reflect fluctuating power purchase prices. In light of CVPS' implementation of the quarterly power cost adjustment mechanism in January 2009, Standard & Poor's ("S&P") reduced its risk factor associated with CVPS' power purchase agreements to 25% from 50%, thus mitigating the company's imputed debt. See Attachment 1 of this response for S&P's RatingsDirect article on CVPS, dated December 22, 2008, which states the following:

> Standard & Poor's Ratings Services has long viewed the company's relationship with state regulators as challenging. However, this relationship appears to be improving as evidenced by the Vermont Public Service Board's (VPSB) recent approval of an alternative regulation plan (ARP) that is in effect through 2011. The framework streamlines cost recovery, reduces earnings volatility, creates incentives for the company to become more efficient and share related savings with customers, and provides for annual base rate adjustments. Importantly, the ARP contains a quarterly power adjustment mechanism, effective Jan. 1, 2009, that provides for more timely recovery of fuel and purchased power costs.
>
> Central Vermont's highly leveraged financial profile is characterized by material off-balance-sheet (OBS) obligations, weak financial parameters, and limited flexibility with regard to certain capital outlays. Central Vermont's purchased power agreements (PPAs) result in material OBS obligations,

> which Standard & Poor's imputes as debt. Central Vermont purchases about 70% of its capacity requirements under purchased-power contracts with Entergy Corp (expires in 2012) and Hydro-Quebec (begin to expire in 2012) at prices that are below or at market rates. We imputed $331 million as OBS debt for these contracts in 2008. However, in light of implementation of the quarterly power cost adjustment mechanism in January 2009, Standard & Poor's will revise its risk factor associated with Central Vermont's purchased-power agreements to 25% from 50%, which will result in a lower adjusted debt burden. Nonetheless, the company must still secure replacement power supplies, which are likely to be much more costly, when the bulk of its existing contracts expire in 2012.

It is Hawaiian Electric Company's understanding from communications with Florida Power & Light Co. ("FPL") that FPL is assigned a 25% risk factor by S&P. However, the only documentation that Hawaiian Electric Company has is S&P's RatingsDirect article dated April 1, 2005, which states a 30% risk factor being assigned to FPL. See Attachment 2 of this response, page 5, which states the following:

> Because power-purchase agreements are a fixed obligation of FP&L, Standard & Poor's assigns a portion of the value of the payments, based on the risk factor, as debt and imputes an associated interest charge in calculating the adjusted coverage ratios. For FPL, a 30% risk factor is assigned, reflecting a high level of regulatory recovery of these costs through the adjustment clause. A 10% discount rate is applied to the fixed capacity payments after the risk factor is applied on all contracts longer than three years. Approximately $1.1 billion is imputed on the balance sheet with a corresponding 10% interest expense component.

Please refer to direct testimony HECO T-20, pages 34 to 41 and HECO-2013 for further discussion on S&P's methodology for imputing debt for power purchase agreements.

b. See response to (a) above.

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December 22, 2008

Central Vermont Public Service Corp.

Primary Credit Analyst:
Barbara A Eiseman, New York (1) 212-438-7666; barbara_eiseman@standardandpoors.com

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Central Vermont Public Service Corp.

Major Rating Factors

Corporate Credit Rating
BB+/Stable/--

Strengths:
- Quarterly power cost adjustment mechanism effective January 2009;
- Diversified customer base with limited industrial exposure;
- Among the lowest retail rates in New England; and
- Low operating risk and current supply contracts at or below market rates.

Weaknesses:
- Challenging, though improving regulatory environment;
- Accelerating construction expenditures;
- Limited spending flexibility on transmission upgrades;
- Liberally leveraged adjusted capital structure; and
- Relatively weak cash flow metrics.

Rationale

The ratings on Rutland, Vt.-based Central Vermont Public Service Corp. reflect an excellent business profile (business risk profiles are categorized as 'excellent' to 'vulnerable') and a highly leveraged financial profile (financial profiles are ranked from minimal to highly leveraged). Central Vermont's business profile benefits from good customer demographics, relatively competitive rates, power supply contracts that are at or below market rates, and minimal operating risk. These factors are tempered by material off-balance sheet obligations, mainly in the form of purchased power contracts, an accelerating construction program with limited flexibility regarding certain capital expenditures, and a challenging, but improving regulatory environment in Vermont.

Standard & Poor's Ratings Services has long viewed the company's relationship with state regulators as challenging. However, this relationship appears to be improving as evidenced by the Vermont Public Service Board's (VPSB) recent approval of an alternative regulation plan (ARP) that is in effect through 2011. The framework streamlines cost recovery, reduces earnings volatility, creates incentives for the company to become more efficient and share related savings with customers, and provides for annual base rate adjustments. Importantly, the ARP contains a quarterly power cost adjustment mechanism, effective Jan. 1, 2009, that provides for more timely recovery of fuel and purchased power costs.

Central Vermont's highly leveraged financial profile is characterized by material off-balance-sheet (OBS) obligations, weak financial parameters, and limited flexibility with regard to certain capital outlays. Central Vermont's purchased power agreements (PPAs) result in material OBS obligations, which Standard & Poor's imputes as debt. Central Vermont purchases about 70% of its capacity requirements under purchased-power contracts with Entergy Corp (expires in 2012) and Hydro-Quebec (begin to expire in 2012) at prices that are below or at market rates. We imputed $331 million as OBS debt for these contracts in 2008. However, in light of implementation of the quarterly power cost adjustment mechanism in January 2009, Standard & Poor's will revise its risk factor associated with Central Vermont's purchased-power agreements to 25% from 50%, which will result in a lower adjusted debt burden. Nonetheless, the company must still secure replacement power supplies, which are likely to be much more costly, when the bulk of its existing contracts expire in 2012.

Capital spending of $41 million in 2008 for core business improvements is considerably higher than the $24 million expended in 2007. Construction expenditures are expected to continue to accelerate largely for transmission and distribution betterments and to deploy an automated meter infrastructure. In late 2007, the company also invested an additional $53 million in investment in Vermont Transco LLC (Transco; not rated) which owns and operates the transmission system in Vermont. This brought the company's total investment in Transco to $83.3 million. The $53 million was initially funded with a bridge loan. In May 2008, the loan was refinanced with $60 of million first mortgage bonds. Central Vermont is expected to invest another roughly $21 million in Transco in 2009. This spending is related to required system upgrades. Although Central Vermont has no legal obligation to contribute equity to Transco, it has long-term economic incentives to do so as it is the main user of Transco's high-voltage transmission system, which interconnects electric utilities in Vermont. Due to the economic incentives and ownership position, Standard & Poor's views Transco-related capital expenditures as nondiscretionary.

Central Vermont's credit metrics are weak. As of Sept. 30, 2008, total adjusted debt, including capitalized PPAs and tax-effected pension and postretirement benefit obligations, was $579.5 million. This large debt burden resulted in an adjusted debt to capital ratio of about 74% and funds from operations (FFO) to total debt of about 10%, which are below our expectations for an investment-grade rating. However, FFO interest coverage remains a relative strength at roughly 2.8x. The November 2008 issuance of $21.3 million common equity will restore some balance to the capital structure. In addition, Standard & Poor's imputation of the lower risk factor will result in stronger adjusted credit parameters in 2009.

Liquidity

Central Vermont maintains sufficient liquidity to cover working capital requirements (including collateral reserves for power contracts) and purchased power on the spot market in the event of short-term power supply interruptions or maintenance outages. If the company's power supply is interrupted for a prolonged period, the company would need to apply for emergency rate relief.

As of Sept. 30, 2008, Central Vermont had $10.7 million of cash and cash equivalents and a $25 million unsecured revolving credit facility. In November 2008, the company renewed the facility for a three year term and increased the facility to $40 million. The facility contains a material adverse effect clause, exercisable when the company's credit rating falls below investment grade, which permits the lender to decline a borrowing request. Central Vermont's credit rating is currently below investment grade, but the banks have never denied a borrowing request. The company is also required to collateralize any outstanding letter of credit (LOC) in the event of a default under the credit facility. At the end of September 2008, there were no borrowings outstanding under the facility, but $6 million of LOCs were outstanding in support of performance assurance requirements associated with the company's power transactions. Central Vermont is required to maintain ratios of total debt to total capital of no more than 65% and minimum interest coverage of 1.75x. As of Sept. 30, 2008, the company's cushion was sufficiently adequate with respect to the facility's financial covenants. There are no rating triggers that would result in debt acceleration.

Central Vermont has a total of $11.1 million of long-term debt coming due in December 2009. The next maturity is material for the company, but does not occur until 2011.

Internal cash flow may fall short of rising capital expenditures, dividends, and investments in Transco, which will necessitate reliance on outside capital.

Outlook

The stable outlook on Central Vermont reflects expectations that credit measures will remain acceptable for current ratings. Continued responsive rate treatment, including recovery of the utility's accelerating construction expenditures, conservative financing, and greater certainty with regard to the company's future power could influence an outlook revision to positive. Downside momentum is possible if cash flow measures deteriorate or debt leverage rises.

Table 1

Central Vermont Public Service Corp. -- Peer Comparison*

Industry Sector: Electric			
	Central Vermont Public Service Corp.	**Empire District Electric Co.**	**IPALCO Enterprises Inc.**
Rating as of Dec. 22, 2008	BB+/Stable/--	BBB-/Stable/A-3	BB+/Stable/--
	--Average of past three fiscal years--		
(Mil. $)			
Revenues	322.1	429.9	1,011.9
Net income from cont. oper.	11.8	32.3	110.5
Funds from operations (FFO)	64.4	100.0	250.5
Capital expenditures	23.5	124.2	167.2
Debt	531.0	576.3	1,758.9
Equity	193.8	483.1	(44.4)
Adjusted ratios			
Oper. income (bef. D&A)/revenues (%)	21.7	31.0	44.0
EBIT interest coverage (x)	1.5	2.3	2.5
EBITDA interest coverage (x)	2.2	3.6	3.6
Return on capital (%)	6.0	7.4	14.8
FFO/debt (%)	12.1	17.4	14.2
Debt/EBITDA (x)	7.7	4.3	4.0

*Fully adjusted (including postretirement obligations).

Table 2

Central Vermont Public Service Corp. -- Financial Summary*

Industry Sector: Electric					
	--Fiscal year ended Dec. 31--				
	2007	**2006**	**2005**	**2004**	**2003**
Rating history	BB+/Stable/--	BB+/Stable/--	BB+/Stable/--	BBB-/Stable/--	BBB-/Stable/--
(Mil. $)					
Revenues	329.1	325.7	311.4	302.3	306.1
Net income from continuing operations	15.8	18.1	1.4	7.5	17.1
Funds from operations (FFO)	64.8	66.8	61.5	64.3	74.2
Capital expenditures	28.3	21.4	21.0	20.5	15.5
Cash and short-term investments	4.8	4.3	100.1	26.8	60.1
Debt	573.2	487.9	531.8	556.9	550.9

Table 2

Central Vermont Public Service Corp. -- Financial Summary*, (cont.)					
Preferred stock	5.0	5.5	12.1	14.1	16.1
Equity	193.8	184.9	202.8	215.2	202.2
Debt and equity	767.1	672.7	734.7	772.1	753.1
Adjusted ratios					
EBIT interest coverage (x)	1.8	1.8	1.0	1.2	1.6
FFO int. cov. (x)	3.1	3.1	2.7	2.8	3.0
FFO/debt (%)	11.3	13.7	11.6	11.6	13.5
Discretionary cash flow/debt (%)	5.1	9.1	0.6	3.5	8.0
Net cash flow/capex (%)	195.0	266.2	235.5	254.3	404.7
Debt/debt and equity (%)	74.7	72.5	72.4	72.1	73.2
Return on common equity (%)	8.3	8.9	0.5	3.2	8.3
Common dividend payout ratio (un-adj.) (%)	60.7	39.3	858.2	156.4	67.9

*Fully adjusted (including postretirement obligations).

Table 3

Reconciliation Of Central Vermont Public Service Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

	--Fiscal year ended Dec. 31, 2007--									
Central Vermont Public Service Corp. reported amounts										
	Debt	**Shareholders' equity**	**Operating income (before D&A)**	**Operating income (before D&A)**	**Operating income (after D&A)**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	186.6	198.9	38.5	38.5	23.3	8.5	34.1	34.1	9.7	23.7
Standard & Poor's adjustments										
Operating leases	9.9	--	2.4	0.5	0.5	0.5	1.9	1.9	--	4.7
Intermediate hybrids reported as equity	5.0	(5.0)	--	--	--	0.2	(0.2)	(0.2)	(0.2)	--
Postretirement benefit obligations	9.6	--	1.3	1.3	1.3	0.1	1.9	1.9	--	--
Capitalized interest	--	--	--	--	--	0.0	(0.0)	(0.0)	--	(0.0)
Power purchase agreements	362.0	--	48.5	48.5	19.3	19.3	29.2	29.2	--	--
Asset retirement obligations	--	--	0.2	0.2	0.2	0.2	(0.1)	(0.1)	--	--
Reclassification of nonoperating income (expenses)	--	--	--	--	7.8	--	--	--	--	--

Table 3

Reconciliation Of Central Vermont Public Service Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)* (cont.)

Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	(2.1)	--	--
Total adjustments	386.6	(5.0)	52.4	50.4	29.0	20.3	32.8	30.7	(0.2)	4.7

Standard & Poor's adjusted amounts

	Debt	Equity	Operating income (before D&A)	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid	Capital expenditures
Adjusted	573.2	193.8	90.9	88.9	52.3	28.8	66.9	64.8	9.6	28.3

*Central Vermont Public Service Corp. reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts.

Ratings Detail (As Of December 22, 2008)*

Central Vermont Public Service Corp.	
Corporate Credit Rating	BB+/Stable/--
Preferred Stock (4 Issues)	B+
Senior Secured (2 Issues)	BBB+
Corporate Credit Ratings History	
10-Jun-2005	BB+/Stable/--
04-Apr-2005	BBB-/Watch Neg/--
18-Jul-2001	BBB-/Stable/--
Financial Risk Profile	Highly leveraged

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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April 1, 2005

Florida Power & Light Co.

Primary Credit Analyst:
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Secondary Credit Analyst:
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Florida Power & Light Co.

Corporate Credit Rating

A/Negative/A-1

Business Profile

1 2 3 [4] 5 6 7 8 9 10

Financial policy (consolidated):

Moderate

Outstanding Rating(s)

Florida Power & Light Co.	
Sr unsecd debt	
Local currency	A-
Sr secd debt	
Local currency	A
CP	
Local currency	A-1
Pfd stk	
Local currency	BBB+
FPL Group Inc.	
Corporate Credit Rating	A/Negative/--
Sr unsecd debt	
Local currency	A-
FPL Group Capital Inc.	
Corporate Credit Rating	A/Negative/A-1
Sr unsecd debt	
Local currency	A-
CP	
Local currency	A-1
Pfd stk	
Local currency	BBB+

Corporate Credit Rating History

July 11, 1995	AA-/A-1+
Sept. 26, 2001	A/A-1

Major Rating Factors

Strengths:

- Florida Power & Light Co. (FP&L) adds stability to FPL Group Inc.'s consolidated cash flow,
- FP&L's strong customer growth with a primarily residential base, and
- Parent FPL's adequate financial performance.

Weaknesses:

- Higher-risk unregulated generation portfolio at FPL Energy contributes less certain cash flow,
- FP&L's increased exposure to natural gas to serve its load,
- Uncertainty regarding several regulatory issues at FP&L, and
- FPL's high consolidated leverage.

Rationale

The ratings on Florida Power & Light Co. (FP&L) reflect the consolidated credit profile of its parent, diversified energy company FPL Group Inc. The consolidated rating on FPL Group reflects the strength of FP&L's stable cash flows. FP&L, which is an integrated electric utility in Florida, contributes about 80% of the consolidated cash flow and has an above average business profile relative to its integrated electric peers. Concerns include the higher-risk cash flows from FPL Energy's portfolio of merchant generation, the utility's increased exposure to natural gas, uncertainty regarding pending regulatory proceedings, and the consolidated company's slightly weak financial profile for the rating.

As of Dec. 31, 2004, Juno Beach, Fla.-based FPL had about $8.5 billion of consolidated debt.

FP&L's strengths include its location in one of the fastest-growing service territories in the U.S. and a predominately residential customer base. The company is in the midst of two regulatory proceedings to be resolved this year that will affect future financial performance: prudency hearings on the recovery of $890 million of storm costs and a request to increase base rates by $400 million to $450 million. Given the magnitude of the requests, a high level of public scrutiny, and rising fuel costs, which increased the average residential bill by about 18% since 2002, it is uncertain how much Florida regulators will grant despite historically constructive treatment.

A longer-term concern is the growing concentration of natural gas in the utility's fuel supply mix, which has caused electricity prices to rise substantially, and underlies the utility's desire to diversify fuel source supply. One alternative that FPL is evaluating is importing liquefied natural gas (LNG) to increase geographic supply diversification. FPL Group Capital's role in LNG supply is not yet determined, but its participation could increase overall business risk should the company take on a project development or ownership role.

FPL Energy's merchant generation portfolio adds business risk. About half of the portfolio is uncontracted, which exposes it to volatile market price risks, and roughly half is concentrated in gas-fired generation, much of it located in regions of oversupply. The company has conservatively forecast that returns on these plants will continue to be minimal; much of the profitability comes from the more stable, fully contracted wind projects and its Seabrook nuclear plant. The merchant portfolio requires FPL Energy to maintain an energy marketing and trading operation that, although small, requires sophisticated risk management and carries the risk of becoming a significant user of liquidity.

FPL's credit-protection measures are mixed. The cash flow ratios, which were lower in 2004 reflecting the impact of the storms, are expected to return to historic levels. The company's 2004 adjusted funds from operations (FFO) to average total debt was 21%, down from about 24% in 2003. Adjusted consolidated total debt to capital remains weak for the rating at 51% as of Dec. 31, 2004. Standard & Poor's expects that FFO to average debt will improve substantially to about 28% over the next three years, assuming the majority of storm costs are recovered. An improvement in adjusted debt to capital is also expected. However, the outcome of the rate case and storm recovery proceedings is likely to have a substantial effect on future financial performance.

Short-term credit factors

The short-term rating on FP&L is 'A-1'. On a consolidated basis, FPL Group's liquidity is adequate based on its bank facilities and cash on hand. FPL Group has $3.5 billion of credit facilities, with $1.5 billion allocated to FP&L and $2 billion allocated to FPL Group Capital. FP&L had $492 million of commercial paper (CP) outstanding as of Dec. 31, 2004, with none outstanding at FPL Group Capital. The CP balances include a portion of the hurricane-related costs that exceeded the balance in the storm reserve. One of the facilities, $1.5 billion, matures in October 2006 with the remaining $2 billion in 2009. A portion of the facility can be used to support LOCs up to certain caps. As of Dec. 31, 2004, the company had posted $237 million in collateral.

Standard & Poor's performed a stress scenario that showed that FPL has adequate liquidity to cover exposure to adverse market and credit events. None of its bank revolvers has rating triggers; however, there are rating triggers in the $400 million bank loan used for construction of some unregulated generation plants. The company has significant maturities of $1.1 billion in 2005 and $1.24 billion in 2006. To repay a portion of the upcoming maturities, $600 million in 2005 and $500 million in 2006 is available from the conversion of the equity units for debt repayment.

FPL's 2004 adjusted FFO was about $1.9 billion, which is in excess of $1.8 billion of capital expenditures (of $1.3 billion for FPL and about $500 million at FPL Energy) and current dividends. For 2005, free cash flow is expected to be stronger as operating income normalizes after the hurricanes and an additional 1,900 MW of generation is brought on line at the Martin and Manatee sites. However, as mentioned above, this situation could decline if the storm recovery proceedings and rate case are not resolved reasonably.

Outlook

The negative outlook for FPL and its subsidiaries is likely to remain until the uncertainty regarding the regulatory requests is resolved. Without any increase in base rates, the consolidated cash flow would be insufficient to maintain the ratings, which could be lowered one notch. In the past, the negative outlook reflected FPL Energy's aggressive growth strategy, but, absent any large acquisitions, this is no longer a drive of the negative outlook because growth on the unregulated side has moderated.

A stable outlook would be predicated on financial performance in line with rating expectations. An outlook revision to stable could be accomplished if recovery of the storm restoration costs are approved without any significant disallowances and an increase in base rates is approved.

Accounting

FPL and FP&L's financial statements are prepared under U.S. GAAP and audited by independent auditors Deloitte & Touche LLP who issued an unqualified opinion.

In analyzing the company's financial profile, Standard & Poor's made the following off-balance-sheet adjustments in 2004:

- Standard & Poor's views several projects as not essential to the company's strategy and are considered noncore. These projects have nonrecourse debt, but are consolidated in the company's financial statements because FPL

Group Capital is the majority owner. Standard & Poor's deconsolidates these projects from the consolidated financial forecast and the dividends are added to FFO. These projects include the $117 million senior secured notes issued for the Bayswater and Jamaica Bay projects and the $435 million project bonds for the Doswell project.

- FPL considers its wind portfolio to be an integral, or core, part of its growth strategy. All of these projects are consolidated in FPL's financial statements because FPL Group Capital is the majority owner. Reflecting this importance, Standard & Poor's deconsolidates only 75% of the project's finances and leaves 25% of the project's finances, including the debt on the balance sheet and in the financial statements. The debt is structured on a nonrecourse basis and does not receive significant parental support. The dividends from the deconsolidated portion are added back to FFO. The net impact of this adjustment to FFO is lower than if the projects remained consolidated in the financial statements. Projects receiving this treatment include the $505 million American Wind transaction, the $465 million National Wind transactions, and the Stateline bank loan.
- In 2002 and 2003, FPL Group Capital issued $1.06 billion of convertible equity units. Standard & Poor's recognizes the certainty of the equity conversion in advance and simultaneously incorporates the debt and associated interest expense, as well as the equity component, in financial ratios while the debt obligation may remain outstanding for two years beyond the common equity issuance.
- The company issued $305 million of trust preferreds, which are treated as debt.
- Because power-purchase agreements are a fixed obligation of FP&L, Standard & Poor's assigns a portion of the value of the payments, based on the risk factor, as debt and imputes an associated interest charge in calculating the adjusted coverage ratios. For FPL, a 30% risk factor is assigned, reflecting a high level of regulatory recovery of these costs through the adjustment clause. A 10% discount rate is applied to the fixed capacity payments after the risk factor is applied on all contracts longer than three years. Approximately $1.1 billion is imputed on the balance sheet with a corresponding 10% interest expense component.

FPL adopted SFAS No. 143 on Jan. 1, 2003, which relates to accounting for asset retirement obligation (ARO). The company recorded AROs totaling $2.2 billion for nuclear decommissioning at FP&L and $152 million for decommissioning at Seabrook with another $12 million for the decommissioning of various wind facilities. The adoption of this statement had no impact on the regulated entities' income because, pursuant to SFAS No. 71, a regulatory asset and a regulatory liability were established, offsetting the impact. The impact to the net income for the nonregulatory assets was immaterial.

FPL adopted SFAS No. 133, requiring that derivative instruments for interest rates and commodity prices be recorded at fair value and included in the balance sheet as assets or liabilities. All of the changes in the fair value of the contracts held by FP&L are deferred as a regulatory asset or liability until the contracts are settled. After settlement, the gains and losses are passed through for recovery through the fuel or capacity clauses. The impact of the nonregulatory changes in fair value as of Dec. 31, 2004 was immaterial.

FPL adopted the revisions to FIN 46 in March 2004, requiring that variable interest entities be consolidated onto the beneficiary company's financial statements if the company is the primary beneficiary of the net losses or benefits. FP&L has a lease for its nuclear fuel, which is consolidated under FIN 46. The consolidated asset as of Dec. 31, 2004 had a value of $370 million. In addition, FPL Energy has an operating lease for the output of a 550 MW combined cycle power plant. The $343 million asset value and $345 million debt are included in the consolidated company's liabilities. Although the net income impact is immaterial, these obligations may increase if FIN 46 becomes applicable to two qualified-facility contracts with FP&L, which are under consideration.

Table 1

FPL Group Inc. Peer Comparison

	--Average of past three fiscal years--				
	FPL Group Inc.	Southern Co.	WPS Resources Corp.	Dominion Resources Inc.	Progress Energy Inc.
Rating	A/Negative/--	A/Stable/A-1	A/Negative/A-1	BBB+/Negative/A-2	BBB/Negative/A-3
(Mil. $)					
Sales	9,322.9	10,673.4	3,962.3	12,089.3	8,820.0
Net income from cont. oper.	813.8	1,441.3	126.4	1,191.7	705.4
Funds from oper. (FFO)	2,065.8	2,802.0	250.1	3,267.8	1,616.5
Capital expenditures	1,322.7	1,855.0	250.3	2,139.0	1,737.3
Total debt	7,821.2	12,531.0	1,036.0	16,696.1	10,399.5
Preferred stock	75.3	427.3	67.8	1,080.0	385.9
Common equity	8,045.7	10,985.3	959.2	10,725.7	7,251.3
Total capital	15,942.2	23,957.0	2,063.5	28,501.8	18,048.8
Ratios					
Adj. EBIT interest coverage (x)	3.0	3.5	3.2	2.5	2.1
Adj. FFO interest coverage (x)	4.9	4.6	7.7	3.6	3.2
Adj. FFO/avg. total debt (%)	23.3	21.5	22.4	17.0	14.4
Net cash flow/capital expenditures (%)	123.8	97.8	69.4	104.7	62.8
Adj. total debt/capital (%)	52.6	52.4	53.3	61.0	60.4
Return on common equity (%)	10.1	13.1	13.6	10.8	9.8
Common dividend payout (%)	52.6	69.7	59.5	67.4	74.6

Table 2

FPL Group Inc. Financial Summary

	2004	2003	2002	2001	2000
Rating	A/Negative/--	A/Negative/--	A/Negative/--	A/Negative/--	AA-/Watch Neg/--
(Mil. $)					
Sales	10,242.6	9,415.2	8,311.0	8,475.0	7,082.0
Net income from cont. oper.	913.8	832.7	695.0	781.0	704.0
Funds from oper. (FFO)	1,885.4	2,139.2	2,173.0	2,029.0	976.0
Capital expenditures	1,308.2	1,383.0	1,277.0	1,099.0	1,299.0
Total debt	7,773.7	7,979.0	7,711.0	6,840.0	5,199.0
Preferred stock	0	0	226.0	226.0	226.0
Common equity	8,618.0	8,048.0	7,471.0	6,015.0	5,593.0
Total capital	16,391.7	16,027.0	15,408.0	13,081.0	11,018.0
Ratios					
Adj. EBIT interest coverage (x)	2.7	3.2	3.2	3.3	3.6
Adj. FFO interest coverage (x)	4.0	4.9	5.9	5.2	3.5
Adj. FFO/avg. total debt (%)	20.9	23.6	25.5	28.1	16.8
Net cash flow/capital expenditures (%)	106.8	123.9	141.0	150.3	47.0
Adj. total debt/capital (%)	50.8	53.1	54.0	56.3	52.4

Table 2

FPL Group Inc. Financial Summary (cont.)					
Return on common equity (%)	9.9	10.3	10.3	12.5	12.8
Common dividend payout (%)	53.4	51.0	53.5	48.3	52.0

PUC-IR-115

Reference: Rate of Return on Common Equity; HECO-RT-19 at 73

In his rebuttal testimony, Dr. Roger Morin recommended a 25 basis points downward adjustment to his cost of equity analysis from a range of 11 .25% - 11.50% to a range of 11 .00% - 11.25%, "assuming approval of decoupling in its existing format."

a) Define "decoupling in its existing format", as used in the referenced statement above.
b) Discuss the impact of other types of decoupling, including decoupling without a Rate Adjustment Mechanism, on the cost of equity.
c) Discuss how other HCEI-related mechanisms proposed by HECO could impact the cost of equity.
d) Discuss and provide your calculations and workpapers to reflect the risk adjustment for each of the HCEI-related mechanisms proposed by HECO.

Dr. Morin's Response:

a. By "decoupling in its existing format" Dr. Morin is referring to the approach to decoupling contained in the Joint Final Statement of Position of the HECO Companies and the Consumer Advocate filed May 11, 2009. This approach may be briefly characterized as the traditional California approach, which 1) trues up revenue to the revenue requirement annually using revenue balancing accounts ("RBAs"), and 2) escalates the revenue requirements annually using the broad-based revenue adjustment mechanism ("RAM") of hybrid form. The Joint Final Statement of Position included a rate base RAM and an operations and maintenance ("O&M") RAM.

b) Hawaiian Electric requested that Pacific Economics Group ("PEG"), its decoupling consultant, provide information on the experience in other jurisdictions in response to this question. The following response was based on information provided by Dr. Mark Lowry of PEG and is being sponsored by Mr. Alan Hee.

A noteworthy class of alternatives to the joint HECO/Consumer Advocate revenue decoupling proposal is one that would have the same decoupling mechanism (based on a revenue balancing account) but a different kind of revenue adjustment mechanism ("RAM"). Prominent alternatives to the proposed hybrid RAM include the revenue per customer ("RPC") freeze detailed by Haiku Design and Analysis ("HDA") and the inflation-only RAM. An RPC freeze would escalate the revenue requirement in proportion to customer growth. Index research reveals that the trend in the cost of a utility equals the trend in its input price inflation less the trend in its productivity plus the trend in its output. The RPC freeze is compensatory provided that input price inflation is equal to productivity so that growth in utility costs equals output growth, as measured by growth in the number of customers served. This assumption generally far from valid. Productivity growth generally is well below input price inflation, so that the nominal retail price of goods and services tends to rise over time.

Under an inflation-only RAM the revenue requirement would be escalated annually for the inflation in a familiar macroeconomic inflation measure such as the gross domestic product price index ("GDPPI"). This is apt to be compensatory provided that productivity growth equals output growth *and* that the GDPPI is a good measure of input price inflation. While the former assumption is sometimes tenable, the GDPPI is known to materially underestimate inflation in the prices of utility base rate inputs.

Due to different flaws, we therefore believe that both the RPC freeze and the inflation-only RAM would be uncompensatory and would not provide the basis for a multiyear rate plan. Rate cases would likely to occur at least as frequently as in the recent past. Compared to the status quo, the effect of such RAMs on the target ROE would be indeterminate. Further discussion on the RPC and inflation-only types of RAMs is found in The HECO Companies' Revenue Decoupling Proposal filed in Docket No. 2008-0274 ("Decoupling docket") on January 30, 2009, pages 11-16.

Another prominent alternative to the proposed approach is to have a revenue decoupling mechanism without a RAM. This approach is likely to necessitate annual rate cases for each of the three HECO companies because of the high likelihood that utilities' costs grow over time. The approach has been used in only a handful of decoupling plans. The target return on equity ("ROE") for this approach would be commensurate with a succession of annual rate cases. Annual rate cases would likely involve some reduction in operating risk compared to the status quo but would involve high regulatory cost and weakened performance incentives for the utility and distract Hawaii's regulatory community from more pressing issues (*e.g.* those raised by the HCEI Agreement).

Still another prominent alternative, straight fixed variable ("SFV") pricing, is discussed by the National Regulatory Research Institute in the Commission's scoping paper (see pages 12 -15) in the Decoupling docket. This would solve the problem of volume risk and revenue would grow along with the peak demand and the number of customers served. However, this approach would discourage conservation and customer-sited renewable generation, raise bills for low-volume customers sharply, and still wouldn't address the tendency of the company's unit cost to rise over time due to such changing business conditions as input price inflation and new investment needs. This approach would likely maintain or increase the frequency of rate cases compared to the status quo and has an indeterminate effect on operating risk. SFV pricing is also discussed in the HECO Companies' response to PUC-IR-5, filed on March 30, 2009, in the Decoupling docket.

Research on the effect of the proposed decoupling mechanism on the cost of capital has been undertaken at the request of the HECO Companies. Based on a review of the orders of U.S. regulatory commissions from 2007 to 2009 that addressed the target ROEs for the currently operating decoupling plans for electric utilities PEG tabulated instances in which the decision included an explicit adjustment to the target ROE due to the inclusion of a decoupling plan.[1]. Differences were calculated separately for vertically integrated and transmission and distribution ("TDUs") utilities. This research found that an explicit adjustment to the target ROE was made in only 5 of 16 cases. Decoupling led to an average reduction in target ROE of 26 basis points. More detailed results of this exercise appear in Attachment 1.

As a second exercise, PEG compared the average of the target ROEs applicable to the recent electric utility decoupling plans with the average target ROEs approved in the same year for electric utilities not operating under decoupling.[2] Differences were calculated for TDUs separately. This research shows that the target ROEs for utilities with decoupling plans were 19 basis points lower on average. More detailed results of this exercise appear in Attachment 2.

Recent Nevada testimony for Southwest Gas reported on the results of a similar survey of U.S. gas distributors.[3] The study considered the target ROEs of 26 approved decoupling plans that were identified by the American Gas Association ("AGA") in its July

[1] PEG excluded from this survey the current rate plans for two Vermont utilities, Green Mountain Power and CVPS. These plans have attributes of revenue decoupling plans but were not acknowledged to be decoupling plans by regulators. In the case of California decoupling plans, decisions concerning target ROEs are made in hearings that are separate from rate case hearings. PEG used the most recent hearing of this kind in their survey.
[2] In the case of California decoupling plans, decisions concerning target ROEs are made in hearings that are separate from rate case hearings. PEG used the most recent hearing of this kind in our survey.
[3] See Prepared Direct Testimony of Daniel G. Hansen on Behalf of Southwest Gas Corporation in support of their 2009 Nevada General Rate Case Application in Docket 09-04003, April 3 2009.

2008 *Natural Gas Rate Roundup* (see Attachment 5). Of the 26 decisions, only seven made an explicit reduction to the target ROE. The average downward adjustment was 12.5 basis points. In two cases, the Commission explicitly rejected an adjustment due to decoupling. In the case of Baltimore Gas and Electric ("BG&E") gas operations, a decoupling adjustment to ROE was rejected because both Staff and BG&E's witnesses had used proxy group data that incorporated the reduction in risk for weather or conservation mitigation.[4] For Consolidated Edison's gas operations, decoupling was part of an overall rate case and was resolved by a settlement which excluded a reduction in ROE due to decoupling.[5]

The Nevada testimony also compared the target ROEs of gas utilities operating under any of three approaches to decoupling --- full balancing account decoupling (similar to that jointly proposed by HECO and the Consumer Advocate), weather normalization, and SFV pricing --- to the target ROEs of gas utilities operating without any of these mechanisms. The source of the ROE data was an AGA database. Utilities with at least one of these three forms of decoupling had target ROEs that were, on average, 30 basis points lower than those approved in the same year for utilities operating without such mechanisms. This result was somewhat sensitive to the distribution of decoupling approval decisions over the years of the sample period. Decoupling decisions were bunched in a year of especially low average ROEs. When this was adjusted for statistically, the average difference was 25 basis points. The results were also sensitive to the typical level of ROE in the states where decoupling plans were approved. For example, commissions that approved decoupling also tended to be commissions that granted low target ROEs. When

[4] Order 80460, p.67 in Case 9036 before the Public Service Commission of Maryland dated December 21, 2005.
[5] Case 06-G-1332, p.27-29 dated September 25, 2007.

this was adjusted for statistically in addition to the time effect, the typical target ROE was actually 6 basis points *higher* with decoupling than without but not significantly different from zero.

An analogous study to gauge the effect on risk of the revenue adjustment mechanism ("RAM") proposed by HECO and Consumer Advocate RAM has not been undertaken. However, the following points are germane.

- HECO and the Consumer Advocate have proposed a RAM that is broad-based in the sense that it adjusts the revenue requirement automatically for changes in multiple cost drivers, including input price inflation and investment. Similarly broad-based attrition relief mechanisms --- some of price cap form and others of revenue cap form --- have been featured over the years in many multiyear rate plans in the United States and around the world (see confidential Attachment 6, PEG's January 30, 2009, report, *Revenue Decoupling for Hawaiian Electric Companies*, filed in Docket No. 2008-0274).
- PEG has monitored alternative regulation for more than a decade (see Attachment 6) and is not aware of any multi-year rate plan (*e.g.* index-based PBR and rate freezes) that occasioned a *reduction* in target ROE or even discussions of the need for a reduction. A likely reason is that the greater risk that results from less frequent rate cases and from automatic adjustments to rates that compensate utilities imprecisely for the financial effects of changing business conditions offsets any risk mitigating benefit of prescheduled rate increases. If anything, multiyear rate plans are generally expected to *increase* operating risk on balance. Any risk mitigating benefits of multiyear rate plans will, in any event, be greater to the extent that utilities are

required to use historic test years since these are more likely to yield a revenue requirement that is reflective of current business conditions.

- It may be noted that there *is* a material risk that the proposed RAM will imperfectly adjust the revenue requirement for the cost impact of changing business conditions. PEG research has shown, for example, that the jointly proposed escalator for O&M expenses[6] would have been undercompensatory to the HECO companies on average if applied over the 1996-2007 period. One reason is that the GDPPI, the proposed inflation index for materials and services ("M&S"), has historically underestimated the inflation in M&S prices by a considerable margin. HDA expressed concern over the design of the proposed RAM, including the risk of indexing O&M expense budgets in this proceeding.[7] Additional sources of risk are the frozen values of baseline capital project plant additions and the rate of return. Both could in principal be indexed.
- HECO will obtain some offsetting risk reduction from the avoidance of rate cases. However, this benefit will be limited because Hawaii's forward test year tradition increases the likelihood that a new revenue requirement reflects current business conditions.

c. Total investment risk results from a multi-dimensional blend of several factors, including business risks, regulatory risks, financial risks, and size. The business risk component can in turn be disaggregated into sub-factors, including demand risk, concentration of demand, customer mix, and service territory economics. The regulatory risk component can also be

[6] The O&M expense escalator consists of the union contract wage increase, less a productivity factor, for labor expenses, and Gross Domestic Product Price Index (GDPPI) for non-labor expenses.
[7] See, for example, HDA's final SOP in Docket No. 2008-0274, pp. 20-22.

disaggregated into broad sub-factors and individual specific ratemaking policies, such as the use or lack of use of normalization accounting, recovery of emission allowance costs, trackers, CWIP, rider mechanisms, fuel clauses, forward vs. historical test year, and pre-approvals. It is difficult to quantify the exact impact of any given factor on the Company's total risk, let alone the impact of sub-factors such as the specific form of a rider/tracker mechanism. Investors examine a number of qualitative and quantitative factors before rendering a risk decision, that such factors are considered both individually and collectively.

For publicly-traded companies, investors determine risk differentials by examining a variety of risk indicators such as betas, market capitalization, bond ratings, S&P Business Risk Scores, price/earnings multiples, market-to-book ratios, common equity ratios, Value Line's Financial Strength, Safety Rank, and Financial Strength ratings. For operating companies that are not publicly traded, investors rely on relative bond ratings, bond yield differentials for comparable maturity bonds, S&P Business Risk Scores, and common equity ratios. The impact of risk-mitigating mechanisms is largely reflected in market data, such as bond ratings, beta risk measures and stock prices.

As discussed in his rebuttal testimony, based on the results of all his analyses, the application of his professional judgment, the risk circumstances of HECO, and the unsettled current market environment, Dr. Morin believes that a conservative just and reasonable return on the common equity capital of HECO's electric utility business is in a range of 11.00% - 11.25% assuming approval of the various risk-mitigating mechanisms sought by the Company and in a range of 11.25% - 11.50% without, or in other words, a 25 basis points reduction in risk with the revenue decoupling mechanism approved.

Moreover, Dr. Morin believes that his recommended return on equity and the various risk-mitigating mechanisms, if adopted, might help to maintain the existing credit ratings, all else remaining constant, through their favorable impact on regulatory risk investor perceptions, interest coverage ratios, and capitalization ratios. Based on his examination of credit rating reports and equity research reports, Dr. Morin believes that the current status of the economy and its impact on demand risk, supply risk, commodity prices, construction risk, regulatory risk, and financial risk (capital structure, interest coverage) are high on the radar screen as this time and constitute the major factors scrutinized by the investment community, rather than details of various species of regulatory mechanisms. Dr. Morin was unable to detect any significant difference in beta risk and bond ratings for electric/gas utilities with or without such regulatory mechanisms.

Of course, assuming a reasonable and supportive decision by the Commission on the Company's application as a whole, adoption of risk-mitigating mechanisms would be viewed favorably by the investment community, may help to maintain the Company's existing credit ratings, and would be viewed as constructive regulation.

See also response to CA-RIR-16.

d. See the response to c.

Attachment 1

SUMMARY OF ADJUSTMENTS TO ALLOWED ROE DUE TO REVENUE DECOUPLING PLANS [1]

Vertically Integrated Electric Utilities	2007	2008	2009	Total
Adjustments With Decoupling Approval				
Idaho Power Company		x	x	
Pacific Gas & Electric		x		
Southern California Edison Co.		x		
San Diego Gas & Electric Co.		x		
Wisconsin Public Service	na	na	x	
Pacificorp (CA)	x			
Portland General Electric	na	na	-0.10	
ROE Adjustments due to Revenue Decoupling Plans for VIEUs	0.00	0.00	-0.10	
Transmission and Distribution Utilities (TDUs)	**2007**	**2008**	**2009**	**Total**
ROE Where Decoupling was Approved				
Delmarva Power & Light Co.	-0.50			
Potomac Electric Power Co.	-0.50			
United Illuminating	na	na	x[2]	
Consolidated Edison[3]	na	-0.10 [3]	x[4]	
Orange & Rockland	na	x		
Central Hudson Electric & Gas	na	na	-0.10	
Baltimore Gas & Electric	na			
ROE Adjustments due to Revenue Decoupling Plans for TDUs	-0.50	-0.10	-0.10	
Explicit ROE Adjustments due to Revenue Decoupling in Current Plans	**-0.50**	**-0.10**	**-0.10**	**-0.26**

[1] The listed numbers only account for explicit changes in the ROE due to the approval of a decoupling plan. An "na" indicates that an entry is not applicable because no decoupling plan was in effect. An X indicates that the decision approving the decoupling plan did not explicitly address the impact of decoupling on ROE. Boxed areas are years in which neither a rate case nor a separate cost of capital application were considered.

[2] In UI's 2009 rate decision, the CT DPUC concluded that although there was no explicit downward adjustment to the ROE to account for a decoupling mechanism, a number of factors (including decoupling) confirm that a lower ROE is necessary in this proceeding.

[3] In the 2008 ConEd rate decision, the NY commission concluded that decoupling reduced the company's overall risk. The Commission upheld the recommended decision's 10 basis point deduction in ROE. However, the NYPSC stated that "the rate mitigation measures and additional revenue adjustments we have adopted create risks and uncertainties which obviate the need for a 10 basis point RDM adjustment."

[4] In this decision, the New York Public Service Commission stated that "no ROE adjustment is proposed or being made to the ROE since the risk reducing effects of the RDM are already reflected in the Company's credit ratings".

Attachment 2

SUMMARY OF ALLOWED ROE FOR ELECTRIC UTILITIES WITH DECOUPLING PLANS[1]

Vertically Integrated Electric Utilities	**2007**	**2008**	**2009**	**Averages**
Idaho Power Co.		x	10.50	
Pacific Gas & Electric		11.35		
Southern California Edison Co.		11.50		
San Diego Gas & Electric Co.		11.10		
Wisconsin Public Service	na	na	x	
Pacificorp (CA)	10.60			
Portland General Electric	na	na	10.00	
Sample Average [A]	10.60	11.32	10.25	**10.84**
Average ROE for all other VIEU Rate Cases [B] *	10.46	10.43	10.68	
Difference in Target ROE between Decoupled and non-decoupled utilities [A-B]	0.14	0.89	-0.43	**0.32**
Transmission and Distribution Utilities (TDUs)	**2007**	**2008**	**2009**	**Averages**
Delmarva Power & Light Co.	10.00			
Potomac Electric Power Co.	10.00			
United Illuminating	na	na	8.75	
Consolidated Edison	na	9.10	10.00	
Orange & Rockland	na	9.40		
Central Hudson Electric & Gas	na	na	10.00	
Baltimore Gas & Electric	na			
Sample Average [C]	10.00	9.25	9.58	**9.61**
Target ROE in Rate Cases of other Wires Utilities [D] **	9.82	10.27	10.48	
Difference in Target ROE between Decoupled and other TDUs [C-D]	0.18	-1.02	-0.89	**-0.62**
Average of Differences for all utilities	**0.17**	**0.12**	**-0.71**	**-0.19**

[1] The listed numbers state the allowed ROE for those utilities operating under decoupling. An "na" indicates that an entry is not applicable because no decoupling plan was in effect. An X indicates that the decision approving the decoupling plan did not state an allowed ROE. Boxed areas are years in which neither a rate case nor a separate cost of capital application were considered.

* See confidential Attachment 3 of this response.
** See confidential Attachment 4 of this response.
Attachments 3 and 4 contain confidential and proprietary third-party information that is submitted subject to protective order.

Confidential Information Deleted Pursuant To Protective Order, Filed on November 21, 2008.

PUC-IR-115
DOCKET NO. 2008-0083
ATTACHMENTS 3-4

Attachments 3 and 4 contain confidential information and are provided subject to the Protective Order filed on November 21, 2008 in this proceeding.

American Gas Association

NATURAL GAS Rate Round-Up

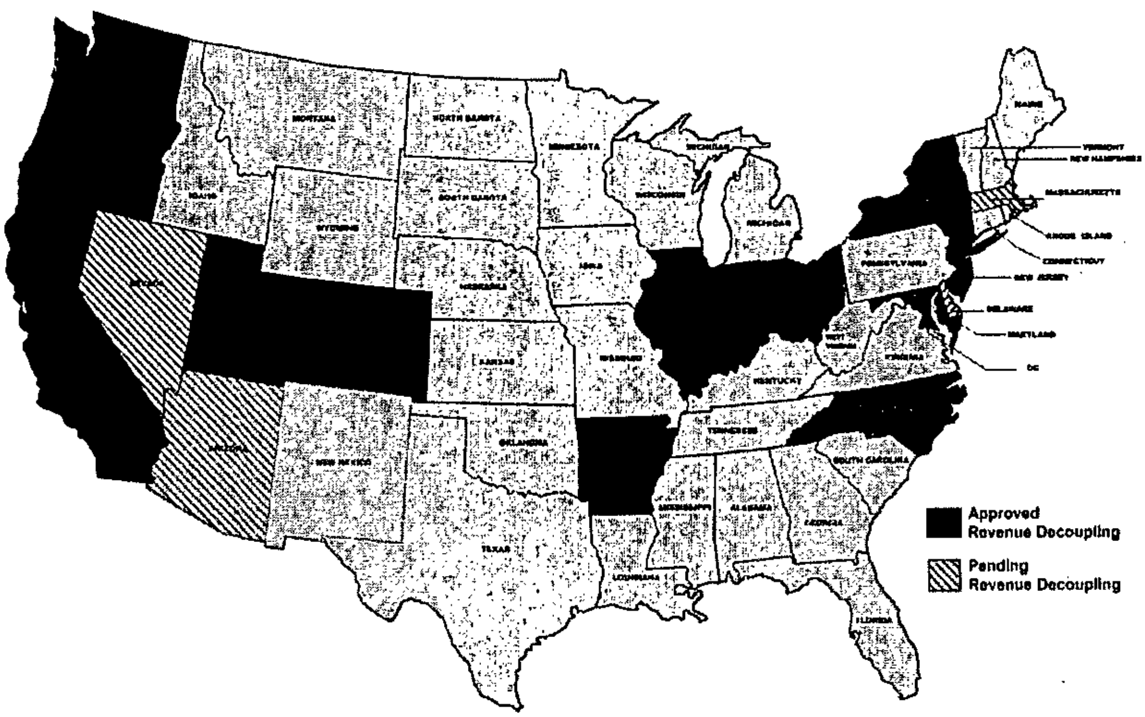
A Periodic Update on Innovative Rate Designs

July 2008

2008 Update on Revenue Decoupling Mechanisms

This Rate Round-Up provides an updated and expanded edition of revenue decoupling reports that AGA has issued every year since 2005. Currently, 26 utilities in 13 states have implemented decoupling tariffs that serve 20 million residential customers. Revenue decoupling cases are pending for 8 utilities, and generic proceedings are before 3 state utility commissions, potentially serving another 5 million residential customers. Revenue decoupling is a rate design method that allows utilities to actively promote energy efficiency while preventing the erosion of margins that is the usual outcome of customer conservation and utility energy efficiency.

STATES WITH NATURAL GAS REVENUE DECOUPLING TARIFFS



DESCRIPTIONS AND COMPONENTS

Decoupling Rate Design

America is facing a dual challenge – meeting ever-increasing demands for energy, while at the same time dramatically reducing greenhouse gas emissions. In this new era, traditional rate designs have become a roadblock that discourages natural gas utilities from promoting energy efficiency and conservation. While utilities' costs for delivering natural gas are relatively fixed regardless of how much natural gas customers use, regulations that have been used to set delivery service rates for the past 100 years are based on the amount of natural gas that flows through the pipes. What was once a regulatory paradigm meant to maximize energy sales is now a regulatory impediment to energy efficiency. The good news is that a win-win solution is possible that benefits both customers and utilities, and will lead to far greater energy efficiency.

The problem is simple. Gas utilities are rate regulated by state public utility commissions and the typical utility rate design in place today penalizes utilities if customers become more energy efficient. Most utilities use a 100-year-old rate design that recovers the fixed costs of a fixed cost business, not on a fixed, per customer basis, but on a volumetric basis. This means that under traditional utility rate design, a utility's earnings and profits will decline if customers conserve.

The solution is also simple. Many states, as well as federal policy makers, now discourage increased natural gas sales and encourage energy efficiency and conservation. Consequently, several states have put in place rate mechanisms that separate, or "decouple", the recovery of fixed distribution system costs from the volume of gas delivered to customers. Revenue decoupling allows the utility to actively promote conservation and energy efficiency without having to sacrifice its financial stability. Revenue decoupling works by adjusting the actual sales volumes to the weather-normalized sales volumes approved during the last rate case. When sales volumes deviate from the level forecasted in the rate case, the true-up mechanism makes a modest adjustment to the distribution charge, which gives the utility an opportunity to recover its authorized fixed costs regardless of fluctuations in energy use.

Energy Efficiency and Conservation Tariffs

The natural gas industry has been a national leader in energy efficiency. Today, the average American home uses a third less natural gas than it did a quarter century ago. The reduction in per-capita natural gas use has been driven primarily by energy efficiency. Homeowners have conserved by adding storm windows, insulation and weather stripping to their homes. Over the past 25 years, gas appliances have become enormously more efficient. Moreover, new construction, although producing increasingly larger homes, has also produced increasingly energy-efficient homes.

Utility-sponsored customer conservation and energy efficiency mechanisms provide consumers with an incentive to conserve natural gas, or provide education to consumers on how to conserve natural gas. Decoupled rates have been associated with strong energy efficiency programs, and conservation and energy efficiency are being addressed in each decoupling proceeding. Decisions about the inclusion of conservation components and energy efficiency programs within a decoupling program are usually based on the effectiveness of existing energy efficiency programs, the relative satisfaction with existing programs, and the relative desire to push for more aggressive energy efficiency programs—and this all varies by state.

Not all utility-sponsored conservation and energy efficiency programs include a decoupling mechanism. Energy efficiency programs administered by natural gas utilities provide customers with practical tools for lowering their utility bills. Effective regulatory approaches help utilities recover lost revenues and preserve financial stability so they are able to partner with their customers in conserving energy. According to a recent survey of AGA member companies, 53 natural gas utilities in 27 states have implemented energy efficiency programs and are recovering all or part of related costs in rates. The programs differ in what costs are allowed recovery (e.g., program costs, administrative costs, lost margin costs), and who administers the program (e.g., company, state, or charitable organization). Several states have approved financial incentives for utilities that invest in energy efficiency, and a growing number of utilities are allowed recovery of lost margins and revenues. The March 2008 Rate Round-Up at http://www.aga.org/NR/rdonlyres/ED01429C-EDC5-477F-B639-2D0953AC97E8/0/0803RATEROUNDUP.pdf discussed the regulatory treatment and cost recovery methods of energy efficiency measures.

Computing the Adjustment and Accounting for Increases in Customer Count

There are several options for calculating the revenue adjustment, or true-up, and while the results are approximately the same, the different options help companies meet unique regulatory preferences and circumstances. The use-per-customer basis makes a rate adjustment that is based on changes in average use per customer, and then applies that adjustment factor against unit margins by customer class. The margin-per-customer rate adjustment is based on the change in baseline marginal revenue per customer compared to the actual marginal revenue per customer. The total margin revenue adjustment is based on comparison of total baseline marginal revenues to actual marginal revenues.

In order to remove the financial disincentive to promoting energy efficiency and conservation, marginal revenues from new customers are retained by the utility. The rate case level of fixed costs has been based on expenses and return on rate base that matches the rate case number of customers, and those costs do not reflect the additional operating costs and return on rate base arising from the addition of new customers to the utility. The fixed costs from those customers can only be recovered through the margins generated by sales to those new customers. Therefore, prior to determining the revenue adjustment, the amount of actual revenue is adjusted by the level of marginal revenue from new customers.

Return on Equity Considerations

Decoupling is a fair and efficient means to design utility rates from the customer's perspective. The change in rate design decouples the recovery of the utility's return on equity from the volumes of natural gas commodity consumed by the utility's customers. The symmetrical nature of decoupling prevents the utility from increasing its earnings by increasing its delivered volumes because any additional distribution charges collected by the utility in that event are refunded to customers. Moreover, decoupling does not shelter the utility from the impact of increased costs and/or provide a guarantee that the utility will achieve its authorized return.

Return on equity is an important cost component that should be calculated after a thorough examination of the utility's risk profile. ROE is established at a level that allows the utility to compete for the attraction of capital with other companies of similar risk profile, and to pay investors a fair return on their investment. Whether the net result of the risk analysis is a material change in the company's risk profile cannot be determined without company-specific and capital market experience. For example, the utility's peer group that is used for the return on equity determination may already include companies whose rate designs are all or partially non-volumetric in design. Factors that are considered in equity return determinations have seldom, if ever, included rate design, and prior to the advent of non-volumetric rates, the choice of a particular rate design rarely, if at all, caused an adjustment to the allowed return.

Of the 31 states that have authorized non-volumetric rates, only two have tied a utility's ROE to the type of rate design. Illinois and New York both adopted a 10-basis point downward risk adjustment to the authorized ROEs that stemmed from the adoption of decoupling mechanisms. It is interesting to note that New York has allowed weather normalization, a non-volumetric rate design known as partial decoupling, for its utilities since 1980 without requiring a similar downward risk adjustment.

Similar Non-Volumetric Rate Design Mechanisms

More than one rate design method exists that will break the link between volumes of gas consumed and cost recovery for the utility. Currently, more than two thirds of the 64 million residential customers in the United States are being served under non-volumetric rates. Fixed variable rate design places all of the utility's fixed costs, including a regulated profit on the value of the utility's investment in plant and equipment used to provide service to the customer, into a fixed monthly charge called a service charge or a demand charge. This charge is similar to the monthly fee charged by cable TV companies and is unrelated to the amount of gas (or number of TV programs) used by the customer. Eight utilities in six states serving 5 million residential customers currently utilize a fixed charge type of rate design for recovery of their costs. AGA discussed this rate design mechanism in the June 2006 Rate Round-Up http://www.aga.org/Template.cfm?Section=Rate_Roundup&Template=/MembersOnly.cfm&ContentID=20563.

Rate stabilization is another rate design mechanism that decouples a utility's profits from its gas throughput. The mechanism works by adjusting the utility's monthly revenues up or down to meet pre-established revenue and return targets. The amount calculated is added to or subtracted from the commodity charge of the utility in the next month, and the utility files a revised rate schedule with the regulator. Twelve natural gas utilities in six states serving 4 million residential customers have received approval for these mechanisms. The December 2006 Rate Round-Up discussed these mechanisms in more detail: http://www.aga.org/Template.cfm?Section=Rate_Roundup&Template=/MembersOnly.cfm&ContentID=20563.

Weather normalization (WNA) is possibly the best known of the non-volumetric, innovative rate designs. Weather normalization is partial decoupling because it breaks the link between utility revenues and weather-sensitive volumetric customer usage. Like full decoupling, it is not a surcharge but a symmetrical adjustment to rates with rebates going to customers when weather is colder than normal. Some companies have established full decoupling and have eliminated their WNA, while others have implemented partial decoupling and have kept the WNA for the weather component. Forty-nine utilities in 25 states and Canada have WNA clauses, and 16 million US customers are covered by weather normalization. The August 2007 AGA Rate Round-Up at http://www.aga.org/NR/rdonlyres/A0F30D84-A9D5-44F0-AA92-A4E443CB3FB8/0/0708WEANORM.PDF discussed weather normalization.

Conclusions

While decoupling imposes no additional costs to the customer beyond those approved in the rate case, the mechanism leads to reduced customer bill variability from stabilized fixed cost recovery. Most important, since the biggest portion of a customer's gas utility bill is the cost of natural gas, greater energy efficiency and conservation lead to significantly lower utility bills. Lower bills also lead to lower bad debt expense, which is a system cost paid by all customers. Finally, reduced overall gas demand could lead to lower natural gas prices.

An independent evaluation of one decoupling tariff[1] found the program to be worthwhile and in the public interest. Among the conclusions of the evaluators were that the mechanism is effective in reducing the variability of utility revenues; the mechanism removes disincentives to promote energy efficiency; decoupling changes the company focus from sales advertising to conservation advertising; the mechanism does not reduce the incentive for good customer service; public purpose funding established in conjunction with the conservation component is beneficial to consumers; and the mechanism does not shift risk to customers.

While traditional rate designs contain a financial disincentive that prevents utilities from aggressively promoting energy efficiency and conservation, revenue decoupling breaks the link between a utility's earnings and energy consumption of its customers without adding any additional customer charges beyond what was approved by regulators. States should energetically consider implementing this innovative rate design.

CURRENT REVENUE DECOUPLING PROGRAMS

✦ APPROVED

1. AR Arkansas Oklahoma-
2. AR –Arkansas Western
3. AR –CenterPoint Energy
4. CA – Pacific Gas and Electric
5. CA - San Diego Gas and Elec.
6. CA – Southern California Gas
7. CA – Southwest Gas
8. CO – PSC of Colorado
9. IL – Peoples Gas
10. IL – North Shore Gas
11. IN – Citizens Gas & Coke
12. IN – Vectren Indiana Gas
13. IN – Vectren Southern Indiana G&E
14. MD – Baltimore Gas and Elec.
15. MD – Washington Gas
16. NJ – NJ Natural Gas
17. NJ – South Jersey Gas
18. NY – Consolidated Edison
19. NY – National Fuel Gas Distribution
20. NC - Piedmont Natural Gas
21. OH- Vectren Ohio
22. OR – Cascade Natural Gas
23. OR – NW Natural Gas
24. UT – Questar Gas
25. WA – Avista Corp.
26. WA – Cascade Natural Gas

✦ PENDING

1. AZ – Southwest Gas
2. DE – Generic Proceeding
3. IL – CILCO
4. IL – CIPS
5. IL – Illinois Power
6. IL – Nicor
7. NC – PS Co. of North Carolina
8. NV – Generic Proceeding
9. NY – National Grid - Niagara Mohawk
10. MA – Generic Proceeding
11. WA – NW Natural Gas

[1] A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural, Christensen Associates Energy Consulting, LLC, March 2005.

Arkansas – Arkansas Oklahoma
On Nov. 20, 2007 the Arkansas Public Service Commission adopted a settlement authorizing Arkansas Oklahoma Gas to implement revenue decoupling for residential and commercial customers. The mechanism, a trial billing determinant rate adjustment is similar to the riders authorized for Arkansas Western Gas and CenterPoint Energy Arkansas Gas.

Arkansas – Arkansas Western
On July 13, 2007, the Arkansas Public Service Commission adopted a settlement authorizing Arkansas Western Gas to implement a trial billing determinant rate adjustment (TBDRA) rider, similar to the decoupling rider proposed by the company, to mitigate the impact of reduced customer gas usage associated with conservation programs on the company's revenues. The TBDRA rider is to remain in place at least through year-end 2012, for measurement periods that conclude on July 31, 2010 and the company is permitted to request an extension of the rider.

Arkansas – CenterPoint Energy Arkansas Gas
On October 25, 2007, the Arkansas Public Service Commission adopted a settlement authorizing CenterPoint Energy Arkansas Gas to implement a trial billing determinant adjustment (BDA) rider to mitigate the impact of reduced customer natural gas usage on company revenues. The company supports the Arkansas commission's efforts to implement energy efficiency program guidelines for the state's utilities, and believes that the current decoupled rate design removes a very strong economic disincentive for the company to support those energy efficiency programs.

California - Pacific Gas and Electric
The only state that has adopted decoupling for both natural gas and electric utilities is California. With the goal of encouraging conservation and with broad stakeholder support at the time, Pacific Gas and Electric (PG&E) decoupled natural gas sales in 1978 and electric sales in 1982. In the 1970s, the California PUC mandated inverted block rate design (increasing levels of consumption are charged higher rates) to encourage customer conservation. However, an inverted rate structure magnifies the impact on revenues of weather, conservation, price elasticity and other sales changes. Decoupling allows pricing signals to customers without revenue loss or gain to the company. The revenue decoupling mechanism is paired with an annual attrition mechanism that adjusts annually for customer growth, inflation, and replacement of aging infrastructure facilities. To address the huge escalation of natural gas costs in the winter after Hurricane Katrina, PG&E deployed several initiatives that encouraged conservation but that reduced its natural gas transportation revenues by $47 million. Without decoupling, the conservation program would have had a negative impact on PG&E's financial performance and very likely would not have been proposed. Today, nearly all of PG&E's revenues are decoupled, with only about 4 percent of natural gas revenues at risk, and support continues to be widespread among stakeholders throughout the state.

California - Southwest Gas
California has had some variation of a decoupling program in place for most of its utilities for nearly 30 years. The impetus for the program was the enactment of lifeline rates legislation, gas supply constraints, and the adoption of demand side management programs by the state. In its most recent general rate case order, effective April 15, 2004, Southwest Gas was granted authority to implement a decoupling mechanism for all customer classes. The decoupling mechanism utilizes a balancing account to protect customers if base revenues exceed authorized levels, and to protect stockholders if base revenues are less than authorized levels. The program is firmly established and utilizes a long-standing regulatory construct that does not recognize an explicit reduction to ROE.

Future test year system annual revenue requirement (margin) is established in a rate case as a fixed dollar amount on a monthly and annual basis. The difference between billed margins and authorized margins, plus carrying costs, is recorded monthly in a deferred account. The account balance is amortized annually through a uniform cents-per-therm rate applicable to all schedules, except special contracts. The test year margin amount increases each January 1 (between rate cases) according to an established formula.

California - Southern California Gas and San Diego Gas and Electric
The decoupling programs at Southern California Gas and at San Diego Gas and Electric are similar to the programs at Southwest Gas and at Pacific Gas and Electric. The decoupling programs at the California utilities apply to all customer classes, including industrial customers.

Colorado – Public Service Co. of Colorado (a Unit of Xcel Energy)
On June 18, 2007, the Colorado Public Utilities Commission authorized Public Service Company of Colorado to adopt a partial revenue decoupling mechanism for residential customers following the adoption of a settlement with modifications. The revenue decoupling mechanism will be in effect on a pilot basis from Oct. 1, 2008, through Sept. 30, 2011, after which the PUC will evaluate the mechanism and determine whether it should be continued, modified, or eliminated. As modified by the PUC, Public Service Company is to absorb the lost revenue associated with the first 1.3 percent of any reduction in gas sales each year. The commission noted that over the past five years gas usage per customer has declined about 2.6 percent annually.

Illinois – Peoples Gas and North Shore Gas (Units of Integrys Energy Group)
On February 6, 2007, Peoples Gas Light & Coke and North Shore Gas were authorized by the Illinois Commerce Commission to implement a decoupling mechanism under which rates will be adjusted to exclude the impact on margin of variations in weather, customer participation in conservation programs, and other factors. The companies also were authorized to implement separate energy efficiency programs, to be recovered through a rider. The decoupling mechanism is updated and true-ups are passed through to customers monthly.

Indiana – Citizens Gas and Coke Utility
In 2007, Citizens Gas and Coke Utility implemented a decoupling mechanism for its residential and commercial customers that is similar to the mechanisms implemented for the Indiana natural gas utilities of Vectren. The Indiana commission initially rejected the company's proposal for a decoupling mechanism. Citizens then appealed the decision, and on rehearing, the commission authorized the company to implement revenue decoupling.

Indiana – Vectren Indiana Gas
Vectren Energy Delivery's decoupling mechanism consists of two interrelated components: the conservation funding rider, and the decoupling mechanism. The company filed a petition rather than a new rate case for the conservation program and settled the filing in 2006. The Energy Efficiency Funding Component is assessed to residential and general service (commercial and small industrial) customers, although Vectren is financing a few items itself.

On February 13, 2007, the Indiana Utility Regulatory Commission adopted a settlement in the company's rate case, authorizing Indiana Gas to implement a slightly modified version of the sales reconciliation component of the energy efficiency rider that had been approved in 2006, in which 100 percent of margins lost as a result of gas conservation are to be recovered. The previous decoupling methodology that had been approved in 2006 required that the SRC charges be reduced by 15 percent to reflect the potential impact upon gas usage of factors other than energy conservation.

Indiana – Vectren Southern Indiana Gas and Electric
Vectren Energy Delivery's decoupling mechanism consists of two interrelated components: the conservation funding rider, and the decoupling mechanism. The company filed a petition rather than a new rate case for the conservation program and settled the filing in 2006. The Energy Efficiency Funding Component is assessed to residential and general service (commercial, small industrial) customers, although Vectren is financing a few items itself.

Maryland - Baltimore Gas and Electric and Washington Gas Light
BG&E's decoupling program began as part of a 1998 base rate case and is a "full decoupling" program, in that it is designed to recover multiple sources of margin loss, including weather and price elasticity, as well as losses caused by customers' conservation and energy efficiency. The Maryland decoupling mechanism utilizes a balancing account that returns to customers excess margin when revenues exceed authorized levels. A conservation component is separate from the decoupling mechanism, which applies to residential and general service firm customers.

BG&E makes adjustments to the delivery price of gas under the applicable schedules to reflect test year base rate revenues established in the latest base rate proceeding, after adjustment to recognize the subsequent change in the number of customers from the test year level. Test year average use per customer is multiplied by the net number of customers added since the like-month during the test year. The product is added to test year revenue to restate test year revenues for the month to include the revised values. Actual revenues collected for the month are compared to the restated test year revenues, and any difference is divided by estimated sales for the second succeeding month to obtain the adjustment to the applicable delivery price. Any difference between actual and estimated sales is reconciled in the determination of the adjustment for a future month. Details of the calculation of the billing adjustment are filed monthly with the public service commission.

In October of 2005, Washington Gas Light implemented a decoupling mechanism outside of a rate case that is similar in design to the decoupling program of Baltimore Gas and Electric. The Washington Gas program applies to all firm customer classes and does not have a conservation component as part of the mechanism.

New Jersey - New Jersey Natural Gas and South Jersey Gas
On October 12, 2006, the New Jersey Board of Public Utilities (BPU) approved requests by New Jersey Natural Gas Co. and South Jersey Gas Co. to replace their existing weather normalization clauses (WNC) with a conservation incentive program (CIP) that would capture gross margin variations related to both weather and customer usage. The three-year pilot programs, which were initiated outside of a base rate case, apply to residential and most commercial customers, who will be segregated in distinct groups to avoid any cross subsidization. The decoupling mechanisms include new conservation programs that will be funded by the company, with additional programs expected to be added during the three year pilot. New Jersey Natural will spend at least $2 million on the new customer conservation efforts, and South Jersey Gas will spend at least $1.2 million.

As with the old WNC calculation, gross margin deficiencies attributable to conservation and other non-weather-related factors will be recovered from customers in the subsequent year through the CIP Rider. However, annual recoveries based on those deficiencies will be limited to a level of agreed-upon gas supply savings. For New Jersey Natural, the initial level of agreed upon savings will be $10.6 million for each year of the pilot. This amount has been realized by releasing capacity, with BPU approval, from New Jersey Natural Gas to NJR Energy Services, the wholesale energy services subsidiary of New Jersey Resources.

The new decoupling program features a return on equity test that prevents New Jersey Natural from recovering any portion of a CIP deficiency charge that would cause the company to earn in excess of its authorized return during the pilot period. The company will have an independent third-party provide a comprehensive evaluation of the effectiveness of the initial two years of the program and will file a report with the BPU no later than April 1, 2009. The BPU may extend, modify or terminate the program at the end of the three-year pilot and if the program is not extended, the WNC program would be reinstated. The program at South Jersey is nearly identical to the New Jersey Natural decoupling program.

New York – Consolidated Edison Company of New York
On September 19, 2007, the New York State Public Service Commission adopted a three year gas rate plan for Consolidated Edison Company of New York that authorized the company to implement a transitional, one-year revenue decoupling mechanism (RDM) and a gas energy efficiency program. For the first rate year of the three-year plan, the $14 million efficiency program will be administered by the New York State Energy Research and Development Authority pursuant to orders issued by the Commission in Case 03-G-1671. A gas collaborative is to be formed to develop a gas efficiency program for rate years two and three, including recommendations for program design, funding levels, administration and incentives for the company. The plan allows for the continuation of Con Ed's weather normalization clause.

New York – National Fuel Gas Distribution Co.
On December 21, 2007, the New York Public Service Commission authorized National Fuel Gas Distribution Co. to implement a Revenue Decoupling Mechanism (RDM) and a Conservation Incentive Program. The mechanisms will allow the company to implement a surcharge and credit mechanism, through which it will be able to recover lost margin associated with conservation savings of customers. As part of the RDM, National Fuel will establish a Conservation Incentive Program with three main components: (1) a low income usage reduction program that would provide insulation and efficient appliances for qualified low income customers; (2) a high efficiency appliance rebate program for residential and small non-residential customers; and (3) a general customer conservation education and outreach effort with a specific low-income customer component that recognizes that low income customers are among the highest consuming residential customers. The decoupling mechanism will apply to residential and small consumption (less than 5000 Mcf annual) customers and was implemented as part of a rate case.

North Carolina - Piedmont Natural Gas
This decoupling tariff, approved by the North Carolina Utilities Commission in the company's November 2005 rate case, gave Piedmont Natural Gas permission to implement a Customer Utilization Tracker (CUT). The mechanism was approved as an experimental, provisional tariff for a period of no more than three years and will automatically terminate on November 1, 2008, unless renewed in a general rate case. During the life of the CUT, Piedmont has agreed to contribute $500,000 per year toward conservation programs. Adoption of the CUT also resulted in the elimination of the company's existing weather normalization adjustment mechanism. In the 2005 ruling, the commission established an approved margin per customer per month for each residential and commercial rate class. Differences between the approved levels and the

actual recovery are tracked monthly in a deferred account and trued-up twice a year. The mechanism applies to residential and commercial customers.

The North Carolina attorney general appealed to the state Supreme Court to overturn the commission action. In July of 2006, Piedmont negotiated a settlement with the attorney general in which the company agreed to an additional contribution of up to $1,500,000 per year, dependent upon the level of conservation related revenues received by the company through the CUT mechanism. The (up to) $1,500,000 will be split 50/50 between a direct reduction in customer rates and further contributions to conservation programs, over and above the $500,000 per year contribution to conservation agreed to in the tariff.

On March 31, 2008, Piedmont filed a rate case with the commission and requested authorization to expand its energy efficiency and conservation programs, and make permanent the CUT. A commission decision is expected prior to November 2008.

Ohio - Vectren
In September 2006, Vectren Energy Delivery received approval from the Ohio Public Utility Commission to implement a conservation tracking mechanism that is designed to provide customers with tools and information to assist them in reducing their energy costs from the level of costs that would otherwise exist absent the program. The program will operate for a minimum of two years and will receive funds from the utility, gas supply portfolio management proceeds, and reduced customer arrearages. The decoupled sales component will recover the difference between actual revenues and revenues approved in the last rate case. The company's most recent rate case came 10 months before the filing, which was settled in April of 2006. The mechanism is assessed to residential and general service (commercial, small industrial) customers.

In 2007, Vectren notified the Ohio PUC that it intended to request an extension of the two-year decoupling rider that was established by the Ohio Public Utilities Commission in September 2006. However, the Ohio Commission Staff indicated that it now prefers straight-fixed variable rate design and has asked the company to modify its rate filing. The PUC is required to complete rate cases within a 275-day period that begins at the time of the actual filing. Therefore, with a late-October 2007 filing, the Commission should complete the case in late July 2008.

Oregon - NW Natural
The Public Utility Commission of Oregon approved a decoupling tariff for NW Natural in September of 2002. The PUC said the tariff was designed "to break the link between an energy utility's sales and its profitability, so that the utility can assist its customers with energy efficiency without conflict." The tariff was a partial decoupling mechanism that allowed NW Natural to defer and then amortize 90 percent of the margin differentials for the residential and commercial customer groups. The mechanism contained two components: 1) a "price elasticity" factor that adjusted for increases or decreases in consumption attributable to annual changes in commodity costs or periodic changes in the company's general rates; and 2) a decoupling adjustment calculated on a monthly basis that accounted for deviations in expected volumes. Weather related risks were not covered by the mechanism. The additional company revenues or credits to customers produced by the mechanism were booked to a deferral account that was reconciled as part of the company's annual purchased gas adjustment.

The NW Natural decoupling tariff was put in place for three years on a pilot basis and had a sunset date of September 30, 2005, unless extended by the PUC. In March of 2005, NW

Natural asked the PUC to investigate whether the decoupling tariff should continue. As part of the petition, NW Natural submitted the results of an independent study that had been required under the original order.

In August 2005, the Oregon PUC extended NW Natural's partial decoupling mechanism for an additional four years. NW Natural revised the decoupling schedule to provide for 100 percent deferral and amortization of the margin differentials. This change eliminated the non-weather related margin variability related to distribution fixed costs. In addition to the decoupling provisions, NW Natural currently has in effect a weather-adjusted rate mechanism (WARM) that was adopted in an earlier rate case and that lasts until September 30, 2008. The WARM covers all residential and small commercial customers, unless the customers opt out. The 2005 decoupling case dictates that public purpose funding and low-income assistance programs will remain in effect throughout the life of the decoupling program. In addition, industrial customers will not be charged or be eligible for any of the assistance programs.

On September 26, 2007, the Oregon PUC adopted a stipulation that extends NW Natural's decoupling mechanism and weather adjustment clause until October 31, 2012, and prohibits the company from filing a new rate case prior to September 1, 2011.

NW Natural has a conservation component to its decoupling program that provides an indirect efficiency incentive to its customers. The company collects from all of its residential and commercial customers a "public purpose" surcharge of 1.5 percent of their total monthly bills. The funds are then passed on to an independent, non-profit organization, the Energy Trust of Oregon. The Energy Trust, which also receives funding from public purposes surcharges from all of Oregon's electric utilities, provides grants to promote energy efficiency and renewable resources among homes and businesses.

The Energy Trust of Oregon disburses approximately $6 million each year to encourage more efficient use of natural gas. Incentives include: $450 - $825 per unit to builders of new home construction if natural gas service is installed; rebates for high-efficiency gas furnaces, water heaters (including tankless units) and other appliances in existing homes; rebates on insulation, new windows and other efforts to reduce home energy use; and rebates on the installation of tankless water heaters, efficient boilers, etc., in commercial buildings.

Oregon - Cascade Natural Gas

Cascade Natural Gas' decoupling mechanism was approved by the Oregon Public Utility Commission on April 19, 2006. The mechanism, which was implemented outside of a rate case, applies to residential and commercial customers, and mitigates demand reduction caused by conservation. The mechanism also adjusts symmetrically for deviations from normal weather. The Conservation Alliance Plan consists of two deferral accounts, one that tracks monthly weather-normalized usage impacts on margins, and another that tracks monthly non-weather related changes in usage on margin. The deferral accounts will be maintained as regulatory assets or regulatory liabilities and will be amortized over the following year as increments to the commodity charge. The Cascade decoupling program includes a 0.75 percent public purpose surcharge to customers and a 0.75 percent of revenue contribution from the company to fund conservation programs for customers.

The Cascade Natural Gas decoupling mechanism imposes service quality requirements, and includes a penalty provision for failing to perform below specified ratios on customer complaints. While there was no reduction to allowed ROE, Cascade's current earnings sharing mechanism was modified to reduce the threshold amount for earnings sharing from baseline ROE plus 300 basis points, to baseline ROE plus 175 basis points. If requested by the commission, the company must file a general rate case in 2008. The plan will remain in effect until September of 2010 and an independent evaluation of the program will be conducted for the parties.

Utah - Questar Gas

Questar Gas received approval for a Conservation Enabling Tariff on October 6, 2006. The three-year pilot program was the result of a four-year process that included numerous task forces and stakeholder groups. The program applies only to the general service class (residential and small commercial) customers and requires the company to aggressively pursue demand side management goals and to fund low-income weatherization programs. The company was granted full decoupling and also kept its previously authorized weather normalization adjustment clause. The program was implemented outside of a rate case.

Washington - Avista

On February 1, 2007, Avista received approval from the Washington Utilities and Transportation Commission to implement a partial decoupling mechanism on a three-year pilot basis. The program, which does not include losses related to weather, will apply to residential and small commercial customers, and rate increases from the program will be capped at 2 percent per year. The company had recently completed a rate case when it filed its petition.

Avista is to defer 90 percent of the non-weather-related margin difference (positive or negative), which is to be recovered from or returned to customers. The recovery of any deferred costs is subject to both an earnings test that would prohibit collection if Avista is earning above its authorized 9.11 percent rate of return, and a demand-side management (DSM) test that would prohibit collection if specific conservation targets are not achieved. Funds not recovered due to the earnings and/or DSM tests may not be carried over to the next period. Also, the commission prohibits Avista from earning interest on deferrals until the deferrals are approved for recovery.

Avista must submit an evaluation of the mechanism and any proposed modifications if it wishes to continue the program after three years. The commission stated that the mechanism will be evaluated, and extension granted, only if there is a demonstration that the mechanism led to cost-effective enhanced conservation.

Washington - Cascade Natural Gas

On January 12, 2007, the Washington Utilities and Transportation Commission authorized Cascade Natural Gas to implement a partial decoupling mechanism on a pilot basis for a three-year period. The mechanism, which will apply to residential and general service commercial customers, would defer non-weather-related margin variances (e.g., changes in usage related to conservation and energy efficiency improvements). In connection with the decoupling mechanism, the settlement called for Cascade to submit a conservation plan, which would be filed after the settlement was approved and an advisory group was convened to review an outside consultant's assessment of the energy efficiency potential in the company's service territory. The settlement specified that the plan would contain targets and benchmarks based on recommendations from the advisory group, and opportunities for penalties and/or incentives. Cascade's program includes paying for customer incentives on rebates for cost-effective demand side management programs, such as high efficiency appliances, insulation and consumer education programs. The decoupling program will be subject to commission approval of a conservation plan, with earnings capped at the authorized 8.85 percent overall rate of return, and will include penalties for failure to meet conservation targets and benchmarks. The pilot program will be evaluated regardless of whether the company seeks to continue the program after the three-year period expires.

PENDING UTILITY CASES

Arizona – Southwest Gas
On August 31, 2007, Southwest Gas filed a rate case at the Arizona Corporation Commission that proposes a non-weather-related decoupling mechanism. The staff of the commission does not support the decoupling mechanism. Southwest previously requested a decoupling mechanism from the Arizona commission, which was denied in 2006. A final commission decision in the current case is expected in September.

Illinois – CILOCO, CIPS, and Illinois Power (units of Ameren)
On Nov. 2, 2007, the Illinois utility operating subsidiaries of Ameren filed with the Illinois Commerce Commission for approval to implement revenue decoupling mechanisms designed to mitigate the impact on revenues of conservation and weather-related variations in gas sales volumes. Ameren has also filed to implement decoupling mechanisms for its Illinois jurisdictional electric utilities.

Illinois – Nicor
On April 29, 2008, Northern Illinois Gas (Nicor) filed a base rate case with the Illinois Commerce Commission and proposed to implement a new "Conservation Partnership Plan," under which Nicor would establish a conservation fund that would be administered by a third-party, with the company to be permitted to implement a revenue decoupling mechanism to mitigate the revenue impact of conservation programs and allow the company to fully recover its fixed costs.

New York – Niagara Mohawk – (A Unit of National Grid)
On May 23, 2008, National Grid's upstate New York operating company, Niagara Mohawk, filed a rate case in which it seeks approval from the New York Public Service Commission to implement a Revenue Decoupling Mechanism (RDM). The RDM would cover residential and commercial customers and calculate the true-up adjustment on a revenue per customer basis. National Grid would also implement an energy efficiency program. The costs of the energy efficiency program and the company's lost revenue would be collected through a systems benefit charge until the RDM goes into effect. National Grid has requested a $95 million rate increase, of which $11 million would be for the system benefits charge.

North Carolina – Public Service Company of North Carolina
On March 31, 2008, Public Service Company of North Carolina requested a customer utilization tracker for residential and customer customers as part of its rate case before the North Carolina Public Service Commission. The company also proposed several conservation initiatives. A decision in the case is expected by November 1, 2008.

Washington – NW Natural Gas
On March 28, 2008, Northwest Natural Gas filed a rate case with the Washington Utilities and Transportation Commission in which it seeks to implement a revenue decoupling mechanism. A decision is expected in March 2009.

PENDING STATEWIDE INVESTIGATIONS

In December of 2007, Congress passed the Energy Independence and Security Act, which modifies the Public Utility Regulatory Policy Act and requires that states consider implementing natural gas rate designs that align natural gas utility incentives with the deployment of cost-effective energy efficiency, and further requires state commissions to consider separating fixed-cost revenue recovery from the volume of transportation or sales service provided to customers. With this directive, many of the states that do not already allow non-volumetric rates will be holding statewide investigations during 2008 to consider changes to their rate design policies.

Delaware
In March 2007, Delmarva Natural Gas settled its gas base rate case with the Delaware Public Service Commission and the parties agreed to investigate the development of a decoupling mechanism through a statewide process with all parties reserving all rights to argue that a ROE adjustment or some other adjustment may or may not be appropriate if a decoupling mechanism is adopted. While the rate case did not propose a conservation component, as part of the company's recent, "Blueprint for the Future" filing, the company did include rebate programs for DSM and energy conservation programs for gas and electric customers in Delaware.

Massachusetts
On August 9, 2007, the Massachusetts Department of Public Utilities (DPU) opened an investigation that is designed to boost conservation, energy efficiency activities, and demand side response by electric and natural gas utilities, and ratemaking mechanisms to promote such efforts. Massachusetts utilities currently operate under Performance Based Regulation (PBR) because the DPU, after extensive review, found that PBR is better suited for promoting the traditional rate objectives of safe, reliable, and least cost utility services. While Massachusetts natural gas utilities support revenue decoupling mechanism because such measures give utilities more of an incentive to push for efficiency measures and increased conservation, they also support the continued reliance on PBR ratemaking. A report is expected in July 2008.

Nevada
In 2006, Nevada enacted SB 437, which requires the Nevada Public Utility Commission to adopt regulations to establish methods and programs that remove financial disincentives that discourage natural gas utilities from supporting energy conservation. Utilities may, but are not required to, implement these programs. The utility is required to file a rate case if it chooses to use a program that removes the financial disincentives. The Nevada commission is currently conducting a hearing pursuant to the requirements in SB 437 and a final regulation, which would not require decoupling for any utility, is not expected for several months.

RESOURCES: COMPANIES, RATE ORDERS, WEBSITES, CONTACTS, ETC.

Arkansas Oklahoma Gas – Arkansas – Approved - Docket No. 07-026-U, 2007, http://apps.puc.state.or.us/orders/2006ords/06-191.pd;

Arkansas Western Gas – Arkansas – Approved - Docket No. 06-124-U, 2007, http://apps.puc.state.or.us/orders/2006ords/06-191.pd;

Ameren – Illinois – Pending – Docket Nos. 07-0588, 07-0589, and 07-0590, November 2007; Contact Bob Mill at 314-554-3734

Avista Corp. – Washington – Approved – Docket No. UG-060518, January 2007; http://wutc.wa.gov/rms2.nsf/vw2005OpenDocket/F1C66EC379B178FE88257412007A22CB; Contact Kelly Norwood @ 509-495-4267

Baltimore Gas & Electric – Maryland – Approved – Maryland Case No. 8780, Feb. 2005, http://webapp.psc.state.md.us/Intranet/CaseNum/NewIndex3_VOpenFile.cfm?ServerFilePath=C%3A%5CCasenum%5C8750%2D8799%5C8780%5C049%2Edoc, Contact Laurie Duhan @ 410-265-4031

Cascade Natural Gas – Oregon – Approved - Docket No. UG 167, April 19, 2006, http://apps.puc.state.or.us/orders/2006ords/06-191.pd; Contact Jon Stoltz @206-624-3900

Cascade Natural Gas – Washington – Approved – Docket No. UG-060256, January 12, 2007; http://wutc.wa.gov/rms2.nsf/frm2005VwDSWeb?OpenForm&vw2005L1DktSh=060256-Documents&NAV999999; Contact Jon Stoltz @206-624-3900

CenterPoint – Arkansas – Approved – Arkansas - Docket No. 06-161- U; October 25, 2007; http://www.apscservices.info/news/06-161-U1FinalOrderNewsRelease.pdf; Contact Chuck Harder at 713-207-7273

Citizens Gas – Indiana – Approved – Indiana URC Cause No. 42767, April 2007; Contact LaTona Prentice @ 317-927-4529

Consolidated Edison Co. of New York – New York – Approved - 06-G-1332, September 19, 2007; http://www.coned.com/documents/gas_tariff/pdf/0002-Table_of_Contents.pdf

Delaware – Statewide Investigation Pending – Regulatory Docket No. 59; Contact Bill Moore at 302-354-1811 or at bill.moore@pepcoholdings.com

Massachusetts Department of Public Utilities – Generic Investigation Pending – August 9, 2007, Docket No. DPU 07-50; http://www.mass.gov/Eoca/docs/dte/electric/07-50/10507dpumem.pdf

National Fuel Gas Distribution Co. – New York – Approved - 07-G- 0141, December 21, 2007; http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/ArticlesByCategory/6FEEF4939FED9F9E852573B8004F0AF6/$File/102_07G0141final.pdf?OpenElement; contact Eric Meinl @ 716-857-7805

Nevada Public Utility Commission – Generic Investigation Pending – June 27, 2007, Docket No. 07-06046;
http://pucweb1.state.nv.us/wx/ISubmitQuery.aspx?Credentials=28:94C2FC7D931B3F4ECAA4F41A202064580941F8BE7B063F5F73835BE9B5A4263F7A9FF0EACEFBF44C8649DB83A24ED30BD5B2E4B457A6716A20C942CD05DCC00E&DSN=PUCN%20Imaging&Appname=DOCKETS_2005_THRU_PRESENT&DOCKET%20NUMBER=07-06046&~~field1=on&~~field2=on&~~field3=off&~~field4=on&~~field5=on&~~field6=on&~~field7=on&~~field8=off&~~field9=off&~~field10=on

New Jersey Natural Gas – New Jersey – Approved – October 12, 2006, Docket No. GR05121020; http://www2.njresources.com/news/trans/newsrpt.asp?Year=2005; Contact Annemarie Peracchio @ 732-938-1129

Niagara Mohawk – National Grid – New York – Pending - 08-G-0609, May 23, 2008; http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/ArticlesByCategory/2F69771F03A15E928525746B00607F9B/$File/166_08g0609.pdf?OpenElement; contact Marcia Collier @ 315-428-5692

Nicor – Illinois – Pending, Docket No. 07-0242; 2008; Contact Bob Mudra at 630-388-2829

North Shore Gas – Illinois – Approved, Docket No. 07-0241; 2008; Contact Valerie Grace at 312-244-4466 or vgrace@pecorp.com

NW Natural – Oregon – Approved - Order No. 05-1041, September 26, 2005; http://apps.puc.state.or.us/orders/2005ords/05-1041.pdf, Contact C. Alex Miller @ 503-721-2487

NW Natural – Washington – Pending – Docket No. UG-080546, March 28, 2008; http://wutc.wa.gov/RMS2.nsf/vw2005OpenDocket/6369CA804F078F9E8825743200683C9B; Contact C. Alex Miller @ 503-721-2487

Pacific Gas and Electric Co. – California – Approved – December 30, 1981, California Application No. 02-02-012, Decision No.93887; Contact Roland Risser @

Peoples Gas – Illinois – Approved, Docket No. 07-0242; 2008; Contact Valerie Grace at 312-244-4466 or vgrace@pecorp.com

Piedmont Natural Gas – North Carolina – Approved – Dockets G-9, Sub 499, G-21 Sub 461, G-44 Sub 15, November 3, 2005; http://ncuc.commerce.state.nc.us/docksrch.html, Contact: David Carpenter @ 704-364-4242

Public Service Company of Colorado – Colorado – Approved – Docket No. 06-656G, 2007; Contact Ron Darnell at 303-294-2180 or ron.darnell@xcelenergy.com

Public Service Company of North Carolina – North Carolina – Pending – Docket No. G-5, Sub 495, March 31, 2008

Questar Gas – Utah – Approved –Docket No. 05-057-T01, October 6, 2006; http://www.questar.com/news/2006_news/01-27-06.pdf, Contact Barrie McKay @ 801-324-5491

San Diego Gas and Electric. – California – Approved – Date, California Application No. 02-02-012

Southern California Gas – California – Approved – Date, California Application No. 02-02-012

South Jersey Gas – New Jersey – Approved – Docket No. GR05121020, October 12, 2006; Contact Sam Pignatelli @ 609-561-9000 x4204

Southwest Gas – Arizona – Pending – Arizona Docket No. G-01551A-07-0504, August 2007; Contact Roger Montgomery @ 702-876-7321

Southwest Gas – California – Approved – California Application No. 02-02-012, Decision No. 04-03-034; Contact Roger Montgomery @ 702-876-7321

Vectren Indiana Gas – Indiana – Approved – Indiana URC Cause No. 42943, December 1, 2006; Contact Scott Albertson @ 812-491-4682

Vectren Southern Indiana Gas and Electric – Indiana – Approved – Indiana URC Cause No. 42943, December 1, 2006; Contact Scott Albertson @ 812-491-4682

Vectren Ohio – Ohio – Approved – Case No. 05-1444-GA-UNC, September 13, 2006; http:/dis.puc.state.oh.us/DMPDFs/GWFLPPVGK@LU501L.pdf; Contact Jerry Ulrey @ 812-491-4138

Washington Gas Light –Maryland – Approved – Maryland Case No. 8990, October 1, 2005, http://webapp.psc.state.md.us/Intranet/maillog/orders.cfm Contact Paul Buckley @ 703-750-5260

ADDITIONAL INFORMATION

If you would like more information about a particular program or would like to speak to another AGA member regarding the details of the program, please contact: Cynthia Marple, AGA director of rates and regulatory affairs, cmarple@aga.org or 202-824-7228.

Confidential Information Deleted Pursuant To Protective Order, Filed on November 21, 2008.

Attachment 6 contains confidential information and is provided subject to the Protective Order filed on November 21, 2008 in this proceeding.